EXHIBIT W

IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF NEW YORK

IN RE: PETROBRAS SECURITIES LITIGATION	)	Case No. 14-cv-9662 (JSR)

Corrected Expert Report of Philip K. Verleger, Jr., Ph.D.

June 2, 2016

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I. Introduction

A. Qualifications and Experience

1. I am the President of PKVerleger, LLC, an economic consulting firm focusing primarily on the function and structure of energy and commodity markets. I received an A.B. in Economics from Cornell University in 1966 and a Ph.D. in Economics from MIT in 1971. I worked as a consultant to the Ford Foundation Energy Policy Project from 1972 to 1974 through Data Resources Inc. I then served as a Senior Staff Economist on President Ford's Council of Economic Advisers and as Director of the Office of Energy Policy at the US Treasury in President Carter's administration. I have been a Senior Research Scholar and Lecturer at the School of Organization and Management at Yale University and a Vice President in the Commodities Division at Drexel Burnham Lambert. While at Drexel Burnham, I worked with several large oil companies to build commodity trading organizations. I also assisted the Kingdom of Saudi Arabia in re-designing its crude oil marketing system. From 1985 to 2012, I was affiliated with the Peterson Institute for International Economics, most recently as a Senior Fellow, and from 1991 to 1994 I was a member of the board of directors of the Valero Corporation. From 2008 to 2010, I served as the David E. Mitchell/EnCana Professor of Management at the University of Calgary's Haskayne School of Business. I have also been a member of the National Petroleum Council since 1998.

2. Over the last forty years I have studied, researched, and published on the function and structure of petroleum markets. In addition, I have consulted for and testified before a number of different government entities, and have also consulted for companies in the energy sector. In addition to my experience on the board of Valero, which ran a large refinery at the time, I have advised Shell and Aroc on refining issues. For ten years I consulted to CITGO, at a time when it was investing in processing heavy crude oil at its refineries, including advising the company on the economics of its refining investments and writing opinions submitted to the US IRS to defend related contracts. My research has been published in leading journals of the field such as *The Review of Economics and Statistics*, *The Bell Journal of Economics*, and *The Energy Journal*. In addition, I have written two books (*Adjusting to Volatile Energy Prices* and *Oil Markets in Turmoil: An Economic Analysis)*, working papers for the Harvard Program on Energy and the Environment, articles on oil matters, and over 100 issues of *The Petroleum Economics Monthly*, which provides detailed examinations of important issues that affect the revenues of petroleum producers, refiners, marketers, and consumers. My curriculum vitae is attached as

Appendix A, and a list of matters in which I have provided testimony in the last four years is attached as Appendix B.

B. Assignment

3. I have been retained by counsel for Petróleo Brasileiro S.A. ("Petrobras") to provide my opinions on whether the cost increases related to Petrobras' capital improvement projects, specifically the Abreu e Lima refinery (also known as RNEST) and the Petrochemical Complex of Rio de Janeiro (also known as Comperj), should have served as "red flags" for Petrobras senior management (including Directors and the Executive Board) that there was fraud in the bidding and construction processes. In forming my opinions in this matter, I have examined a number of related questions, including:

- How did factors in the international oil sector, such as oil prices and capital expenditures, change during the relevant time period of the planning and construction of the RNEST and Comperj refineries?
- How did regulations in Brazil and Petrobras' status as a national oil company affect these Petrobras projects?
- How did factors in the Brazilian market, such as cost of construction, availability of suppliers, inflation, and exchange rates, affect these Petrobras projects?
- How did these Petrobras projects evolve over time, for example in terms of cost estimates and scope?
- Given these market- and project-specific factors, is it likely that any cartel overcharges should have been detected by Petrobras senior management?
- Should cost increases on Petrobras projects have been interpreted as indication of any cartel overcharges?

4. In addition, I have been asked to evaluate whether as a result of Petrobras' purchase of 50 percent of the Pasadena Refining System, Inc. ("PRSI" or the "Pasadena refinery") from Astra Oil ("Astra") in 2006, and in light of Astra's prior purchase of the refinery, Petrobras senior management reasonably should have known of the bribery that has since been revealed to have been a part of that transaction.

C. Materials Considered

5. In the course of my work, I have considered case documents received from Counsel, industry publications and data, analyst reports, press articles, SEC filings, and other company documents. I do not read Portuguese, and have therefore relied on English translations of documents for which the original language is not English. I may supplement this report in the event that new information relevant to my opinions is produced in the case. A complete list of the materials I have considered for this assignment is included in Appendix C.

6. I am being compensated in this matter at a rate of $1000 per hour. I have been assisted by staff at Analysis Group working under my direction and supervision. My compensation is not contingent on the content of my opinions or on the outcome of this matter.

II. Summary of Opinions

7. Cost increases and delays for the RNEST and Comperj projects would not have been surprising when viewed in the context of: (1) the challenges associated with undertaking grassroots (from the ground up) oil processing and conversion megaprojects; (2) contemporaneous developments in the oil industry and developments in Brazil; and (3) significant changes in scope for these projects over time. The cost increases encountered in these Petrobras projects reasonably could have been seen as a natural result of these factors and therefore would not have been a signal of fraud at Petrobras.

- Decisions to invest in these Petrobras projects were made at a time of rapidly growing demand for capital investment and rising oil prices globally. The oil industry is characterized by a rush to build projects when the market is tight (*i.e.*, when prices are rising and refinery utilization is increasing), which leads to increasing development costs. As these Petrobras projects evolved, capital expenditure costs were increasing substantially for building oil refineries globally.

- Megaprojects, including oil refinery projects, often experience delays and go over budget. There are several factors that commonly contribute to these outcomes across projects, including internal factors related to project management and external factors related to regulatory and geopolitical challenges. Many of the same factors that regularly plague oil and gas megaprojects also affected the RNEST and Comperj projects at Petrobras.

- Other refinery projects during the same time period also faced increasing development costs and challenges commonly associated with megaprojects, leading to substantial cost increases and delays.
- Economic and social policy and changes in macroeconomic conditions in Brazil resulted in cost increases for both the labor and materials required in construction projects within the country, which consequently also led to cost increases for these Petrobras projects. I understand Professor Edwards expands on these topics in his report.[1]
- The RNEST and Comperj projects changed in scope substantially over time due to changing market conditions and unsuccessful joint venture proposals, which further contributed to cost increases.

8. The price Petrobras paid for 50 percent of the Pasadena refinery in September 2006 was in line with comparable transaction values at the time, when refinery purchase prices were increasing substantially. The purchase price reflected: (1) changes in the market since Astra purchased the refinery 20 months earlier, primarily driven by increases in refining margins, which led to higher prices per barrel for refinery acquisitions; and (2) Astra's subsequent investment of $112 million in the refinery. Therefore, when Petrobras purchased the Pasadena refinery, it would not have been a red flag to Petrobras senior management of the bribery that has since been revealed to have been part of the transaction.

Philip K. Verleger

[1] *See* the Expert Report of Sebastian Edwards, dated May 27, 2016 ("Edwards Report"), particularly Section 4: "Macroeconomic Factors Contributed to Increases in Costs of Large-Scale Construction Projects in Brazil During the 2006 to 2014 Period."

III. Background

A. Crude Oil and Refining

9. The oil and gas industry comprises two primary segments, exploration and production ("E&P") and refining and marketing ("R&M"). E&P, as the name implies, includes the search for oil reservoirs and the drilling of oil wells, either onshore or offshore, to produce crude oil and natural gas. This is referred to as the upstream side of the business. R&M, on the other hand takes the crude oil, refines it into products such as gasoline, and sells these products, either through the oil company's own retail outlets or to unaffiliated retailers. R&M is considered the downstream part of the business.[2] Some oil and gas companies will focus on the entire process from the locating and drilling for oil to the refining of oil and sale of products to consumers. Such companies are what economists call vertically integrated. Other companies may choose to focus on only crude oil production or crude oil refining.[3]

1. What is crude oil?

10. Broadly speaking, crude oil is composed of the remains of ancient plants and animals that, over very long time frames and under conditions of intense heat and pressure beneath the surface of the earth, are transformed into a liquid comprising a wide range of hydrogen and carbon compounds known as "hydrocarbons."[4] One important fact about crude oil is that it is not a homogeneous commodity, despite the treatment as such by business journalists or in the popular press. While one often hears news on "oil prices," the prices being referred to are usually for only one of two types of crude oil: West Texas Intermediate ("WTI"), a type of crude from Texas, or Brent, a crude mix from the North Sea. While the prices of these two types of crude oils are used as benchmarks for much of the world, there is a vast array of crude oil types. Each

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[2] "Industry Overview," Petroleum Services Association of Canada, http://www.psac.ca/business/industry-overview/ (last visited May 25, 2016).

[3] A third part of the process involves the movement of crude oil from oil fields or offshore platforms to oil refineries. This is referred to as the midstream part of the business and can involve using pipelines, ships, rail cars, or even trucks. Large oil terminals, such as those in Cushing, OK, are included in this segment as well. How a refinery obtains its supply of crude oil depends on a number of factors, including where it is located and how much crude it intends to process. Large refineries on the Gulf Coast of the United States that supply products to large areas of the country may obtain their oil by ship, whereas small refineries in more isolated parts of the country that supply to local markets, such as rural New Mexico, may simply truck their oil in directly from oilfields. *See* "Industry Overview," Petroleum Services Association of Canada, http://www.psac.ca/business/industry-overview/ (last visited May 25, 2016).

[4] "According to the generally accepted theory, oil is the product of animal and vegetable fossils compressed and heated over time." *See* "The International Crude Oil Market Handbook," Energy Intelligence Research, 2010, p. A16.

type of oil has its own set of characteristics which make it either more or less valuable than either of these two benchmarks.

11. Crude oils are roughly classified by two primary characteristics: how dense they are and how much sulfur they contain. Denser crude oils are referred to as being "heavy," while less dense oil is referred to as being "light." How heavy or light a crude oil is depends on the types of hydrocarbons that it is composed of. Lighter crude oils, like WTI and Brent, are made up of a greater proportion of the types of hydrocarbons that comprise gasoline, jet fuel and diesel fuel, for example. Conversely, heavier crude oils have lower quantities of these hydrocarbons and higher quantities of more tar-like hydrocarbons.[5] Given the higher prices of products such as gasoline, lighter crude oil generally commands higher prices than heavier crude oil.[6]

12. The hydrocarbons that make up crude oil have many contaminants in them, with some crude oil containing trace elements of up to 50 metals.[7] The primary contaminant is sulfur. The other main dimension for classifying crude oil is the level of sulfur. Crude oils with lower sulfur levels are referred to as "sweet," while those with higher sulfur content are referred to as "sour."[8] When hydrocarbons such as gasoline are combusted in an engine, the sulfur that is in the gasoline is converted into sulfur dioxide. This is then released from a car's tailpipe into the atmosphere. Not only is sulfur a pollutant in its own right, when sulfur is present in gasoline it impedes the effectiveness of vehicle emissions controls, which then leads to increases in the emissions of other pollutants such as nitrogen oxides (which lead to smog) and carbon monoxide released into the atmosphere.[9] Since sulfur needs to be removed from fuels before they can be

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[5] Hydrocarbons "range from methane (CH4), ethane (C2H6), propane (C3HS), butane (C4H10) - all of which are gases at atmospheric pressure - to gasoline (averaging C8H18), kerosene (averaging C12H26), diesel (averaging C12H23) and light and heavy fuel oils, which are all liquids. Other substances in crude include waxes, with 25 carbon atoms per molecule, and asphalt, with 35." *See* "The International Crude Oil Market Handbook," Energy Intelligence Research, 2010, p. A29.

[6] "The real key to the value of crude is the price of the products that can be obtained from it. Each of these oil products has an individual market of its own. Each crude produces different volumes of these oil products. The value of the crude is thus a composite of the value of the products it produces, but this value is constantly changing. Since different crudes produce different volumes of these products, the value of some crudes will vary in relation to others as demand for the products fluctuates." *See* "The International Crude Oil Market Handbook," Energy Intelligence Research, 2010, p. A29.

[7] "The International Crude Oil Market Handbook," Energy Intelligence Research, 2010, p. A29.

[8] "The International Crude Oil Market Handbook," Energy Intelligence Research, 2010, p. A30.

[9] "It is impossible to clean the air, or in particular to reduce air pollution from the transportation sector, without getting sulfur out of fuels… No significant air pollution reduction strategy can work without reducing sulfur to near-zero levels." *See* Blumberg, Katherine, Michael Walsh, and Charlotte Pera, "Low-Sulfur Gasoline & Diesel: The Key to Lower Vehicle Emissions," The International Council on Clean Transportation, May 2003, p.2.

sold in many markets, refining sour crude oils into low-sulfur fuels involves a more intensive operation as described below. Sweet crude oils will therefore command a higher price than will sour crude oils.[10]

13. The terms light and heavy, and sweet and sour are relative, but the industry uses measures to quantify how heavy and how sour each crude oil is. The heaviness of a crude oil is measured by its "API gravity." The lower the API gravity, the heavier the crude oil.[11] How light or heavy a crude oil is will often correlate with how much sulfur is in the crude oil. Generally, lighter crudes will be sweeter, and heavier crudes will be sourer, but this is not always the case.[12] These are important factors in the design of an oil refinery.

14. Another characteristic of crude oil that can also influence the design of a refinery is its acid content.[13] Crude oils with higher acid content may require some of the refinery's processing units to employ more expensive metallurgy, such as certain types of stainless steel, in their construction.[14]

2. What is an oil refinery?

15. An oil refinery is an industrial complex in which crude oil is "processed" or "upgraded" to generate various types of hydrocarbon products such as butane, gasoline, jet fuel, kerosene, diesel fuel, heating oil, fuel for ships (known as bunker fuel), and many other products.[15] A refinery consists of various "processing units" which handle specific parts of the process for turning crude oil into these products. For example, some processing units remove sulfur from a

[10] "The International Crude Oil Market Handbook," Energy Intelligence Research, 2010, p. A30.
[11] "The International Crude Oil Market Handbook," Energy Intelligence Research, 2010, p. A29.
[12] For example, "West Texas Intermediate (WTI), the main US marker crude, has an API of 40° and a sulfur content of 0.3%. Russian export blend crude has an API of 32° and 1.2% sulfur, while Mexican crude Maya is 22° API and 3.3% sulfur. Iran's Nowruz crude is 18°-19° API and 3.5% sulfur, and Venezuela has, amongst other lighter crudes, an estimated 35 billion [barrels] of extra-heavy, 8°-9° API material with 3.8% sulfur." *See* "The International Crude Oil Market Handbook," Energy Intelligence Research, 2010, p. A30.
[13] Acid content is measured by a "Total Acid Number" or TAN. Naphthenic acid is one of the main acids of concern. *See* "The International Crude Oil Market Handbook," Energy Intelligence Research, 2010, p. A30. *See also,* "Crown Central Petroleum Pre-Feasibility Study: Marlim Crude Processing," July 2001, pp. IV-1.
[14] "Crown Central Petroleum Pre-Feasibility Study: Marlim Crude Processing," July 2001, pp. IV-1 – IV-4.
[15] Refer to "Summary of the Downstream Process" table in "The International Crude Oil Market Handbook," Energy Intelligence Research, 2010, p. A33.

particular product, some processing units increase the octane[16] of the hydrocarbons that become gasoline, and some processing units separate the crude oil into the hydrocarbons that become gasoline or diesel fuel or other types of fuel products.[17]

16. After the gasoline, diesel, and other products are separated from the crude oil, a refinery may have a number of other types of processing units that take the heavier hydrocarbons that are left over and break them apart. When these heavier hydrocarbons, which may be worth less than the crude oil they come from, are broken apart, it creates the types of lighter hydrocarbons that also make up gasoline and diesel fuel. This process of taking lower-value, heavier hydrocarbons and breaking them into higher-value hydrocarbons is called upgrading, and is a critical part of the refining process.[18]

17. Just as most crude oils are distinct from one another, so too are most refineries distinct from one another. This is not a coincidence. One of the most important factors that helps determine the design of a refinery is the type (or types) of crude that the refinery will process. Another key factor in the design is the relative amounts of the various types of products that are desired. If a refiner wants to make primarily low sulfur content gasoline and diesel fuel from a light, sweet crude, the refinery will not need to be designed to do much upgrading or sulfur removal. If, on the other hand, a refiner wants to make primarily low sulfur content gasoline and diesel fuel from a heavy, sour crude, the refinery design will need to incorporate more upgrading and sulfur removal capacity. In other words, the refinery will need to be more complex, which in turn means that it will be more expensive to build.[19] In addition, by changing the design of a

[16] Octane is a measure of how gasoline will perform in an internal combustion engine. ("In fact, most gasoline comes from processing the lighter naphtha. The most important specification for gasoline is its octane number, a measurement of the tendency of the gasoline to ignite prematurely - or knock - an internal combustion engine. Very roughly, the higher the octane number, the more efficiently the engine will run, hence 'high octane' becoming a slang euphemism for high speed or power.") *See* "The International Crude Oil Market Handbook," Energy Intelligence Research, 2010, p. A47.

[17] The process of removing the sulfur and nitrogen in jet kerosene, diesel and heating oil is known as hydrotreating. Reforming is the process of converting naphtha into high-octane "reformate" that is sent on for processing into high-octane gasoline. Separation is achieved through heating the crude oil hydrocarbons into fractions with different boiling point ranges. *See* "The International Crude Oil Market Handbook," Energy Intelligence Research, 2010, pp. A31-A32.

[18] This part of the process is also known as "cracking." *See* "The International Crude Oil Market Handbook," Energy Intelligence Research, 2010, p. A32.

[19] For example, ExxonMobil announced in December of 2008 that it planned to spend $1 billion in refinery upgrades to allow them to produce 6 million gallons per day, equivalent to143 thousand barrels of heavy crude oil per day ("MBPD") of low sulfur diesel fuel. *See* "ExxonMobil sets $1 billion diesel plan," Oilgram News, vol. 86, no. 248, December 17, 2008. This is equivalent to about $7,000 invested per barrel of low sulfur diesel production. Also, PDVSA planned to spend $1.8 billion to increase the

refinery, a refiner can alter how much of each type of product it produces. For example, different types of upgrading unit(s) are required for different products, such as gasoline as compared with diesel fuels. Whether the refiner would like to focus on producing more gasoline or more diesel fuels will affect which types of upgrading unit(s) are incorporated into the refinery design.[20]

3. Oil Refining Economics

18. At a high level, gross margins for an oil refinery are determined by the difference between the value of the products it sells and the price of the crude oil it processes. The market value of the products produced from a refinery is referred to as "gross product worth." Refinery margins are measures of the difference between the gross product worth and the price of the crude processed, including transportation costs. These values are based on the market prices of the particular products sold and the particular crude oil.[21] Margins increase when product prices are higher relative to crude oil prices. When margin spreads are high, refining crude oil will generally be a more profitable enterprise. When margin spreads are low, refining crude oil will be less profitable. Benchmark spreads, however, are not completely informative when applied to an individual refinery because, as I've discussed above, each refinery can be designed to process different types of crudes and make a different mix of products. More complex refineries will be able to process cheaper (*i.e.*, heavy and sour) crude oils and make more expensive products, so their gross margins will be higher. The profitability of a refinery, however, also depends on the

capacity of four refineries to process heavy crude oil in 1992. *See International Petroleum Encyclopedia*, 1992, p. 27.

[20] The International Crude Oil Market Handbook provides an example of the tradeoffs of upgrading: "In a simple refinery, 45% of the crude will remain as residue, while in a highly complex one, it will only be 6%. In between lie the yields of the refinery complex in Rotterdam and the more sophisticated ones of the US Gulf of Mexico. It would thus seem logical that all refinery capacity should be upgraded to the highest standards. But this ignores the cost of investment and the expected rate of return of the upgrading, or of a new refinery. A 25,000 b/d hydrocracker can cost as much as $500 million, while a new 25,000 b/d coker is priced at around $250 million. Neither of these capital costs include the additional operating costs, or indeed any refinery downtime required during installation. There is a trade-off between the additional value of the new products and the additional investment costs, which will, in turn, depend on a host of geographical and market factors." *See* "The International Crude Oil Market Handbook," Energy Intelligence Research, 2010, p. A37.

[21] "The International Crude Oil Market Handbook," Energy Intelligence Research, 2010, p. A38.

costs to run the refinery. More complex refineries that process heavy, sour crude oil have more units and will therefore be more expensive to build and operate.[22]

B. Background on Petrobras

1. Integrated Oil and Gas Company with Extensive E&P Operations

19. Petrobras is an integrated oil and gas company that accounts for the majority of Brazil's oil and gas production. According to Petrobras, oil and gas E&P in Brazil represents the largest component of the company's portfolio. Approximately two-thirds of Petrobras' capital expenditures in 2014 were investments in E&P, and the E&P segment was the only net income-generating segment of the company in 2014 (with the exception of the company's smaller oil distribution segment). Petrobras maintains a fully developed operational infrastructure throughout the country to facilitate these activities. As of 2014, Petrobras produced approximately 2 million barrels of oil per day ("BPD") in Brazil and had net proved crude oil and natural gas reserves in Brazil of approximately 12.7 billion barrels of oil equivalent.[23] Petrobras is also involved in refining, transporting, marketing, and distributing oil products, as well as producing gas, power, and biofuels in Brazil and in 16 additional countries worldwide. In fact, Petrobras operates substantially all of Brazil's oil refining capacity, although it does not yet have the capacity to process a sufficient amount of oil to satisfy Brazil's growing demand.[24]

20. Petrobras was incorporated in 1953 as a vehicle to conduct oil and gas production and refining activities on behalf of the Brazilian government, and the Brazilian government is mandated by law to be the company's controlling shareholder. The Brazilian government has the power to elect a majority of Petrobras' directors, and maintains control over the company's investment budget and debt limit. As described by Petrobras, this relationship with the government means that the company "may engage in activities that give preference to the objectives of the Brazilian federal government rather than to [the company's] own economic and business objectives."[25]

[22] The Energy Intelligence refining model, which makes a series of calculations to arrive at a gross product worth and refining margin, considers refinery complexity as one of its inputs. *See* "The International Crude Oil Market Handbook," Energy Intelligence Research, 2010, pp. A39-A41.
[23] 5,350 cubic feet of natural gas is considered equivalent to one barrel of oil. *See* "BP Statistical Review of World Energy June 2015," BP, 64th Edition, June 2015, p. 44.
[24] Petrobras Form 20-F for the Fiscal Year Ended December 31, 2014, pp. 32-34, 37, 96.
[25] Petrobras Form 20-F for the Fiscal Year Ended December 31, 2014, pp. 26-27.

2. Brazil's Goal of Energy Independence

21. Brazil has long held the goal of being oil self-sufficient. In fact, the government's vision at the time of Petrobras' founding was that the company would be a fully integrated oil company that could eventually allow Brazil to achieve energy independence. Following the international oil crisis of 1973-1974, the Brazilian government further emphasized oil self-sufficiency as a national priority and increased funding to Petrobras for upstream and downstream activities.[26] It is during this period that Petrobras made major investments in oil refining in Brazil, including building its most recently completed refinery, which was completed in 1980.[27] Petrobras did not construct any new oil refineries in Brazil between 1980 and the 2000s.[28] However, by the early 2000s, it became increasingly clear that Brazil faced a refining shortage, raising the possibility that Brazil would become a net importer of all refined oil products and fail in its long-term goal of achieving energy independence.[29]

22. In early 2007, the Brazilian government launched a vast infrastructure development plan called the Programa de Aceleração do Crescimento (Growth Acceleration Program), known as "PAC," which originally called for R$646 billion of investments in social, logistical, and energy infrastructure from public and private sources.[30] One of the stated goals under PAC was energy independence. Specifically, the program called for the country to maintain long-term self-sufficiency in oil production and for Brazil to boost and modernize its oil refining industry, as well as increase the role of local Brazilian companies throughout the processing chain.[31]

23. In November 2007, Petrobras announced its discovery of large oil reserves in deep and ultra-deep waters under a large salt layer off the Brazilian coast (termed the "pre-salt" reserves).[32]

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[26] Guan, Erjia Joy, "Understanding Brazil's Oil Industry: Policy Dynamics and Self-Sufficiency," Journal of Emerging Knowledge on Emerging Markets, Nov. 2010, Vol. 2, pp. 77, 80, 82.
[27] Oliveira, Patricia and Edmar Almeida, "Determinants of fuel price controls in Brazil and price policy options," 5th Latin American Energy Economics Meeting, 2015, p. 6; Petrobras Form 20-F for the Fiscal Year Ended December 31, 2005, pp. 44-45.
[28] Petrobras Form 20-F for the fiscal Year Ended December 31, 2005, pp. 44-45.
[29] McCarthy, Marc, Rodrigo Goes, and Alex Monroy, "Who Will Close the Refining Gap? How will Rousseff Make It Attractive? Trade Balance Could Grow to $6 bn with No Inv't," Bear Stearns, January 17, 2003, pp. 1-2.
[30] "Sobre o Pac," PAC, http://www.pac.gov.br/sobre-o-pac (last visited May 25, 2015); Savaris, Bruno , Felipe Vinagre, and Daniel Magalhaes,"The Brazilian Infrastructure: It's 'Now or Never,'" Credit Suisse, July 29, 2013, p. 18.
[31] Carvalho, Marcelo, Giuliana Pardelli, Gullherme Palva, Subhojit Daripa, Carlos De Alba, Javier Martinez, and Nicolai Sebrell, "Brazil Infrastructure: Paving the Way," Morgan Stanley, May 5, 2010, pp. 54-55.
[32] "Plunging in," The Economist*,* February 14, 2009; Petrobras Form 20-F for the Fiscal Year Ended December 31, 2014, p. 35.

Initial estimates were that the pre-salt discoveries contained potential reserves of 5 to 8 billion barrels of oil equivalent, making it the largest ever deep-water oil discovery.[33] These estimates have continued to grow over the years, with the Brazilian oil regulator (ANP) estimating total potential reserves at 80 billion barrels of oil equivalent as of 2009.[34] The pre-salt finding was viewed as a "game-changing" development, with President Lula declaring that the pre-salt reserves represented a "second independence of Brazil."[35] Investments in the development of the pre-salt region were also categorized as PAC energy projects.

24. Given Petrobras' dominance in the Brazilian oil industry, the Brazilian government's stated energy goals under PAC were primarily centered around increased oil exploration and production, and refinery construction at Petrobras.[36] By 2012, Petrobras' investments under PAC represented 35 percent of the program's total investments, including pre-salt exploration activities and expansions of the country's refinery system through upgrades to existing refineries and the development of new refineries.[37] RNEST and Comperj are categorized as PAC projects; in fact, both refineries were highlighted in Petrobras' initial public statements following the government's launch of PAC in January 2007.[38] RNEST was announced in 2005 with the expectation that the refinery would process 200 thousand barrels of heavy crude oil per day ("MBPD"). Construction on RNEST was expected to start in 2007, with initial operations expected to begin in 2011.[39] Comperj was announced the following year, with the expectation that the complex would process 150 MBPD of heavy crude, as well as petrochemicals.

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[33] "The next oil giant?" The Economist, March 19, 2009.
[34] "The next oil giant?" The Economist, March 19, 2009.
[35] Victor, David, David Hults, and Mark Thurber, *Oil and Governance*, 2012, p. 551; Schutte, Giorgio Romano, "Brazil: New Developmentalism and the Management of Offshore Oil Wealth," European Review of Latin American and Caribbean Studies, No. 95, 2013, pp. 50-51.
[36] Carvalho, Marcelo, Giuliana Pardelli, Gullherme Palva, Subhojit Daripa, Carlos De Alba, Javier Martinez, and Nicolai Sebrell, "Brazil Infrastructure: Paving the Way," Morgan Stanley, May 5, 2010, pp. 55-56; "Petrobras, partners to spend $80 billion through 2010 in Brazil," Platts Commodity News, January 22, 2007; "Govt growth plan includes 183 Petrobras projects," Business News Americas, January 23, 2007.
[37] Schutte, Giorgio Romano, "Brazil: New Developmentalism and the Management of Offshore Oil Wealth," European Review of Latin American and Caribbean Studies, No. 95, 2013, p. 61; "Brazil," European Commission Energy Research Knowledge Centre; "Petrobras PAC Projects Focus on Refining System Expansion, Upgrade," Latin America News Digest, January 25, 2007.
[38] "Petrobras, partners to spend $80 billion through 2010 in Brazil," Platts Commodity News, January 22, 2007.
[39] Petrobras Form 20-F for the Fiscal Year Ended December 31, 2005, p. 45; Petrobras Form 20-F for the Fiscal Year Ended December 31, 2006, p. 67; "Brazil Petrobras New Refinery in Pernambuco – Energy Minister," Latin America News Digest, February 14, 2005.

Construction on Comperj was expected to begin in 2007, with operations scheduled to commence in 2012 (soon after the expected completion of RNEST).[40]

25. In 2009, the company released a business plan calling for $174 billion in capital spending for the 2009 to 2013 period, over one quarter of which was allocated to downstream investments.[41] Many reporters and analysts following the company viewed Petrobras' aggressive investment plans, including upgrading existing refineries and development of new refineries, as being heavily influenced by the government's energy goals.[42]

26. Petrobras expanded its refining goals the following year, allocating one-third of its projected $224 billion of investments to the downstream sector. Petrobras also reported that oil production in Brazil and Brazilian demand for oil both exceeded the country's refining capacity, and stated its long-term plan to achieve "greater balance and integration" between oil production, refining, and demand.[43] The increased emphasis on developing the refining sector was largely viewed negatively by market participants, with many noting the political nature of the investment plan. Analysts at Credit Suisse responded to the plan by stating, "we still believe that these investments are primarily politically driven and, if carried out, will be very detrimental not only to the profitability of downstream markets in Brazil… but to Petrobras' returns as a whole."[44] Analysts at Barclays further noted, "[s]tructurally, we think there has been a visible change in the Brazilian government's thinking around the role of Petrobras. We think the change has been triggered by the company's recent success in their pre-salt discoveries and the fact that the country has now become self-sufficient in oil supply."[45] Analysts at JP Morgan emphasized the unprecedented nature of Petrobras' mandate to deliver energy independence to Brazil:

> In brief, [Petrobras] has the self-appointed responsibility of single-handedly supplying the large Brazilian fuels market (2.1 million bd), which is also one of the fastest growing

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[40] Petrobras Form 20-F for the Fiscal Year Ended December 31, 2006, pp. 50-51; "Petrobras, partners to invest US$6.5bn in Rio refinery/petchem complex," Business News Americas, March 29, 2006.
[41] Petrobras Business Plan 2009-2013, pp. 11, 27.
[42] *See*, for example, "Plunging In," The Economist, February 14, 2009.
[43] Petrobras Business Plan 2010-2014, pp. 8, 18-20, 35.
[44] Leite, Emerson, Vinicius Canheau and Marcos Guerra, "Stock over penalized, buy on deflating capitalization concerns," Credit Suisse, February 10, 2010, p. 6. Analysts at Deutsche Bank expressed similar concerns. *See* Sequeira, Marcus, "Capitalization newsflow still impacting the stock," Deutsche Bank, February 19, 2010, p. 1; Sequeira, Marcus, "PBR announces new (and increased) 2010 capex," Deutsche Bank, March 22, 2010, p. 4; Sequeira, Marcus, "Lowering PT on short-term concerns and higher capex," Deutsche Bank, June 30, 2010, pp. 3, 5.
[45] Cheng, Paul Y., Christina Cheng, and Danielle Diamond, "Downgrade to 2-EW," Barclays Capital, October 6, 2010, p. 3.

globally (3%-4% CAGR expected in 5 years). No other company in the GEM or global universe of coverage by JPM faces such a challenging task. We contend that refining upgrades to meet new fuel specifications and the new planned refineries may not add value if executed at the high cost reflected in the existing business plan.[46]

27. During the period that the Brazilian government encouraged increased energy investment under PAC, the government also continued to encourage Petrobras to build out local industries by requiring a high percentage of materials and labor used in the oil and gas sector be sourced locally. Petrobras worked closely with the government to go beyond the level of local content that is legally mandated in both the upstream and downstream sectors.[47] I understand that Professor Edwards expands upon this topic in detail in Section 3 of his report.

IV. State of the Global Oil Industry in the 2000s

28. The global oil industry experienced a rush of capital investment in both downstream and upstream markets in the years preceding the 2008 financial crisis. This rush was caused by a combination of factors, including high prices of crude oil and high refining margins, exacerbated by inadequate global refining capacity to keep up with the growing demand for refined products. The increased level of capital investment, in turn, caused a shortage in raw materials and labor, driving up construction costs and leading to cost increases throughout the industry. In this section, I explain the rise in the prices of crude oil and refined products, the increase in investment in oil and gas construction projects, and the rise in the cost of capital investment in the oil industry in the first decade of the 21st century.

A. High Oil Prices and Refining Margins

29. From 2001 to early 2007, crude oil prices increased steadily. As shown in Exhibit 1, in late 2007 and 2008, the price of WTI crude oil, one of the global oil price benchmarks, rose sharply, to a high of $145 a barrel in July 2008.[48] The rise in oil prices during the decade was not completely unexpected, and in fact, it was anticipated by some industry experts. In the fall of 2004, in an article published in an economic policy magazine, I explained that the mismatch between the rising oil consumption in the developing world, most notably in India and China,

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[46] Torres, Sergio and Felipe Dos Santos, "The Other Side of the Elephant; We Reiterate Our Neutral - Rating, Establish YE11 Price Targets," JP Morgan, November 1, 2010, pp. 7-8.
[47] Petrobras Sustainability Report 2011, p. 124; Petrobras Sustainability Report 2012, p. 16.
[48] EIA data on West Texas Intermediate (WTI) crude oil spot prices.
James D. Hamilton, "Causes and Consequences of the Oil Shock of 2007-08," Brookings Papers on Economic Activity, Spring 2009, p. 215.

and the inability of oil production to meet the increased demand in the short term would lead to an increase in oil prices. I argued that "[c]rude prices could rise from present levels of roughly $50 per barrel to perhaps $60 by mid-2005 and as high as $80 in 2006 should 'shortage conditions' be experienced in those years. Even higher prices might occur later in the decade."[49] As the trends of continued economic growth in developing countries and tight refining capacity continued, I argued in two separate articles in 2006 and 2007 that oil prices would continue to rise and would eventually break $100 per barrel, which did happen in early 2008.[50]

Exhibit 1
West Texas Intermediate (WTI) Daily Closing Crude Oil Spot Prices
2000-2016

Note: WTI sourced from Cushing, OK.

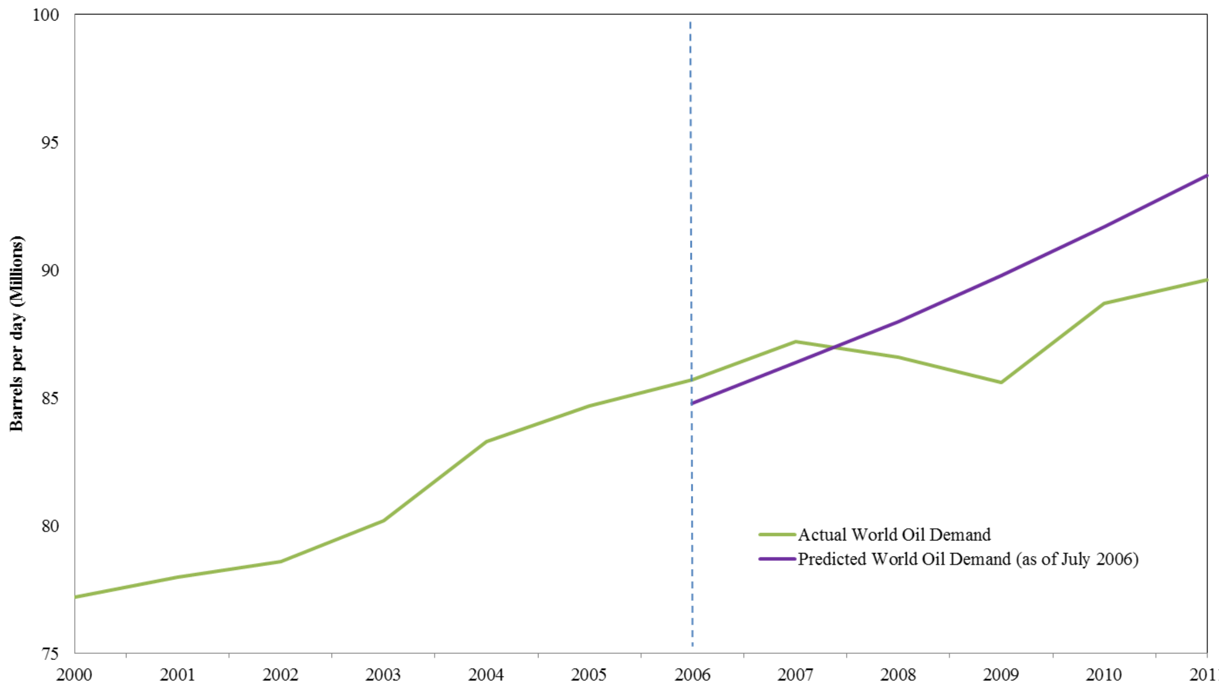
Source: U.S. Energy Information Administration's Petroleum and Other Liquids dataset, https://eia.gov/dnav/pet/PET_PRI_SPT_S1_D.htm (last accessed May 26, 2016).

30. Energy analysts projected that demand for oil would continue to increase well after 2007. In 2006 and 2007, the International Energy Agency projected that world oil demand would grow at

[49] Verleger, Philip, "Why oil could go to $60," International Economy, Fall 2004, pp. 23, 25.
[50] Verleger, Philip, "Hundred dollar oil, five percent inflation, and the coming recession," International Economy, Winter 2006, pp. 16-19, 58-63; Verleger, Philip, "The coming triple-digit oil prices," International Economy, Fall 2007, p. 53.

around 2 percent per year on average through 2012.[51] In 2006, the Energy Information Administration predicted an average annual growth rate of 1.4 percent through 2030.[52] These forecasts were similar to those in the 2005 PIRA Energy Group report presented to Petrobras as part of its evaluation of the RNEST project, which projected that worldwide oil demand would grow at an average rate of 1.2 percent to 2.8 percent per year through 2020.[53] Exhibit 2 below shows world oil demand as predicted by the International Energy Agency in 2006 was expected to steadily increase through 2011.

Exhibit 2
Actual and Predicted World Oil Demand
2000-2011



Notes:
[1] World oil demand is measured as deliveries from refineries and primary stocks, and includes both OECD and non-OECD demand.
[2] Actual world oil demand is taken from the 2015 IEA "Oil Market Report: Annual Statistical Supplement."
[3] Predicted world oil demand for 2006-2011 is taken from the 2006 IEA "Medium-Term Oil Market Report."

Sources:
"Medium-Term Oil Market Report," IEA, July 2006.
"Oil Market Report: Annual Statistical Supplement," International Energy Agency, 2015.

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[51] "Medium-Term Oil Market Report," International Energy Agency, 2006, p. 9; "Medium-Term Oil Market Report," International Energy Agency, 2007, p. 11.
[52] "International Energy Outlook 2006," U.S. Energy Information Administration, 2006, p. 26.
[53] "Analysis of Global Refining for Petrobras and the PDVSA," PIRA Energy Group, June 2005, (PBRCG_01629388), p. 1.

31. An important consideration here is that the increased demand—and prices—for crude oil were primarily for light sweet crude. The inability of the supply of light sweet crude to meet demand was the primary driver of the dramatic spike in oil prices in 2007 and 2008, when the price per barrel of WTI more than doubled from an already high level of approximately $70 per barrel to $145 per barrel. Furthermore, regulatory measures were planned and implemented globally during this period requiring gasoline and diesel fuel to have lower sulfur levels,[54] forcing refiners around the world to change the mix of crude input.[55] As explained in Section III.A, whereas it is possible to produce fuels with low levels of sulfur from sour crudes, the refining process is much more complex and expensive, and can only be done by sophisticated refineries. While the demand for light sweet crude increased, available crude oil in the global markets was becoming heavier and sourer, a problem that was exacerbated by several shocks in the supply of light sweet crude, such as military conflict in Nigeria.[56]

32. Analysts noted the growing disparity between the demand for light fuels and worldwide refining capacity. In 2005, the International Energy Agency estimated that 95 percent of the projected increase in oil demand would be for middle distillates and light fuels, such as diesel and gasoline.[57] As demand for these products grew, spare refining capacity diminished rapidly.[58] In addition, available crude oil was expected to be heavier and sourer over time.[59] To meet the projected increased demand for lighter fuels using this heavier, sour crude oil, the global oil industry needed to invest in expanding capacity. This expansion also required investment in the expensive equipment needed to upgrade the heavy crude to lighter products

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[54] For example, the European Union enacted regulatory measures Euro I-VI, *see* "European Union Emissions Standards," Lubrizol, https://www.lubrizol.com/EngineOilAdditives/ACEA/ReferenceMaterial/EuropeanUnionEmissionsStandards.html (last visited May 9, 2016). The US, Australia, Canada, Japan and South Korea also agreed to continuous improvement in their emissions standards, *see* "Global Comparison of Light-Duty Vehicle Fuel Economy/GHG Emissions Standards," International Council on Clean Transportation, August 2011, p. 3.

[55] "Medium Term Oil Market Report 2009," International Energy Association, 2009, pp. 29, 76.

[56] Verleger, Philip, "Structure Matters: Oil Markets Enter the Adelman Era," The Energy Journal, Vol. 36, SI 1, 2015, p. 144; "World Energy Outlook 2008," International Energy Agency, 2008, p. 102, 207, 197, 198, 218, 303, 304, 311; "Medium-Term Oil Market Report," International Energy Agency, July 2008, p. 55; "Consequences of a heavier and sourer barrel," Petroleum Review, April 2007, p. 30.

[57] Middle distillates refer to products of the refining process, such as diesel and kerosene, which are heavier than light distillates (e.g., gasoline), but lighter than heavy distillates (e.g., heavy fuel oil, lubricating oils). *See* "World Energy Outlook 2005," International Energy Agency, 2005, p. 82.

[58] "STEO Supplement: Why are oil prices so high?" U.S. Energy Information Administration, 2006, p. 4; "World Energy Outlook 2005," International Energy Agency, 2005, p. 45.

[59] "World Energy Outlook 2005," International Energy Agency, 2005, p. 97; "Consequences of a heavier and sourer barrel," Petroleum Review, April 2007, p. 30.

and to remove higher amounts of sulfur from the increasingly sour crude.[60] As I explain in more detail in the next section, by 2006 and 2007, investment in refinery capacity had increased substantially.[61] However, much of the additional capacity from this investment was not expected to be available until after 2011, and refining bottlenecks persisted in the short term.[62]

33. The higher demand for light fuels and limited refining capacity led to an increase in refining margins (*see* Exhibit 3 below, which demonstrates increasing spreads in the stylized margin between a weighted average of gasoline and diesel fuel less WTI, often referred to as a 3-2-1 crack spread).[63] PIRA Energy Group, in a June 2005 report presented to Petrobras evaluating the RNEST refinery, stated that they expected refining margins to remain higher than historical averages due to the increased demand for refined oil products and limited refining capacity.[64]

[60] "World Energy Outlook 2005," International Energy Agency, 2005, p. 97.
[61] "Medium-Term Oil Market Report," International Energy Agency, 2006, p. 8; "Medium-Term Oil Market Report," International Energy Agency, 2007, p. 6.
[62] "Medium-Term Oil Market Report," International Energy Agency, 2007, pp. 9-10, 53-55; "STEO Supplement: Why are oil prices so high?" U.S. Energy Information Administration, 2006, p. 4.
[63] See Section III.A for more detail about crack spreads.
[64] "Analysis of Global Refining for Petrobras and the PDVSA," PIRA Energy Group, June 2005, (PBRCG_01629388), pp. 1, 4.

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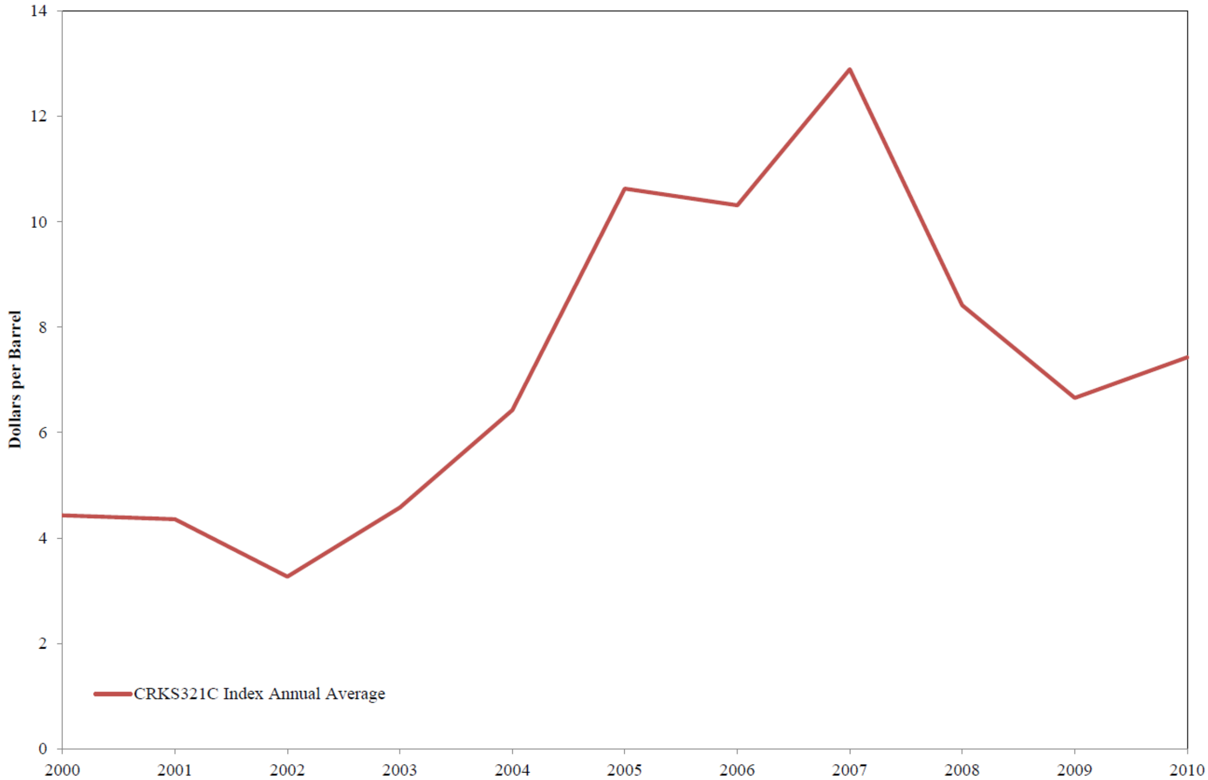
Exhibit 3
WTI Cushing Crude Oil 3-2-1 Crack Spread/US Gulf Coast Index



Source: Bloomberg, CRKS321C Index.

34. As can be seen in Exhibit 1, the increase in oil prices came to an abrupt end in July 2008. Before the end of the year, WTI oil prices had fallen more than 70 percent, from a peak of $145 per barrel to approximately $40 dollars per barrel.[65] The drop in oil prices was caused primarily by a change in the direction of the demand. As can be seen in Exhibit 2, due to the 2008-2009 financial crisis and recession, which affected nearly every economy in the world, global demand for oil fell in 2008 and 2009, even though it was previously expected to keep increasing. The drop in demand for oil products also affected refinery margins, as can be seen in Exhibit 3. As a consequence, the profitability of oil and gas projects dropped. According to McKinsey, after the "Golden Age" of refining ended in 2008, "the global downstream industry has seen dramatic shifts in fundamental supply and demand trends. The 2009 crisis lowered global demand for oil products, and while global demand has rebounded since, it is at structurally lower rates of

[65] Bloomberg data, CRKS321C Index.

growth. At the same time, refining capacity continues to grow at a strong pace, especially east of Suez. The result is growing overcapacity and downward pressure on utilization and margins."[66]

35. In the next section, I discuss how capital investment in the oil industry responded to the fluctuations in oil prices and refining margins.

B. High Oil Prices and Refining Margins Led to Increased Capital Investment

36. High oil prices, increased demand for refined products, increased refining margins, and stricter fuel regulations led to increased capital expenditures in the oil industry, both in the upstream and downstream sectors. As of 2006, major oil and gas companies planned to invest $2.1 trillion between 2006 and 2010, a 57 percent increase from the $1.4 trillion that was invested in 2001-2005.[67]

37. In the E&P sector, the increase in the price of crude oil pushed firms to pursue sources which were previously too expensive or too risky to extract. Investment poured into previously uneconomic ventures, such as shale oil in the United States, oil sands in Canada, arctic drilling, and deep water reserves around the world, including in Brazil.[68] Increased investment was also influenced by international organizations concerned about the economic consequences of increasing oil prices. For example, in 2004, International Monetary Fund managing director Rodrigo Rato, explaining that the rise in demand-driven oil prices would have an adverse impact on economic growth, called on oil-producing nations to boost investment in production facilities.[69]

38. In the downstream market, the increase in refining margins and stricter fuel standards led to a rush to upgrade existing refineries and build new refineries which could process a global oil mix that was expected to become increasingly heavier and sourer into the low sulfur fuels markets demanded.[70] The failure to adequately invest in global refining capacity to keep up with the

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[66] "Profitability in a world of overcapacity," McKinsey & Company, May 2015, p. 1.

[67] After adjusting for cost inflation, this represents a 40% increase. *See* "World Energy Outlook 2006," International Energy Agency, 2006, p. 320.

[68] *World Energy Outlook 2008*, International Energy Agency, 2008, pp.102, 197, 198, 207, 218, 303, 304, 311.

[69] "IMF chief calls for more investment in oil production," Platts Global Alert, October 22, 2004.

[70] "Refiners within Europe, Japan and the US have been required to invest substantial amounts to keep their refinery output in line with the stricter quality specifications. Their governments' policies have reduced on-road diesel-sulphur levels from 350-500ppm to 15-50ppm, with Europe moving to 10ppm sulphur at the end of the decade. Gasoline quality specifications have been similarly tightened with lower sulphur, aromatics and benzene levels allowed." *See* "Medium-Term Oil Market Report," International Energy Agency, July 2006, p. 48.

growing demand for refined products earlier in the decade, which led to high margins for refineries and large profits for oil companies, compounded the incentives to invest in new refining projects which take years to complete.

39. In its *World Energy Outlook 2005*, the IEA reported that "[t]he global oil-refining industry has an urgent need for more distillation and upgrading capacity. As a result of strong growth in demand for refined products in recent years, spare capacity has been rapidly diminishing and flexibility has fallen even faster. Effective capacity today is almost fully utilized, so growing demand for refined products can only be met with additional capacity. Upgrading capacity will be needed even more than distillation capacity, since demand will continue to shift to lighter products, while crude oil production is becoming heavier, with a higher sulphur content."[71]

40. In 2007, the IEA reported:

> [W]hile the current tight markets for transportation fuels reflects structural demand shifts and a lack of upgrading capacity, the strong (even super-normal) margins available to complex refineries are providing a powerful incentive to invest in upgrading capacity. These market signals are clearly working. Large-scale upgrading capacity additions of 7.2 mb/d over the next five years […] reflect not only the complex nature of the proposed new refineries, but also the significant investments taking place at existing plants. The work is predominantly concentrated in the addition of coking units to upgrade fuel oil and maximize gasoil[[72]]/gasoline production and hydrocracking[[73]] units to maximize middle distillate output. These investments are needed to address the current tightness in light products, to prepare for the longer-term projected trend towards more heavy/sour crudes and to attempt to capture the high return available due to a depressed fuel oil market.[74]

41. As explained in Section IV.A, in 2008 the global financial crisis brought a sharp reversal in the trends in the oil industry, leading to lower demand, and consequentially lower crude oil prices and refining margins. Although refining profitability decreased substantially, previously

[71] "World Energy Outlook 2005," International Energy Agency, 2005, p. 45.

[72] Gasoil is a heavier middle-distillate product usually used as diesel fuel or home heating oil. *See* "The International Crude Oil Market Handbook," Energy Intelligence Research, 2010, p. A126.

[73] Hydrocracking is "[a] secondary refinery upgrading process similar to catalytic cracking that converts heavy, processed feedstocks such as vacuum gas oil into lighter products such as gas oil, kerosene and gasoline by passing the feedstock over a heated catalyst in the presence of hydrogen in order to break clown, or crack, the heavy hydrocarbons into lighter ones and add carbon molecules to make the output lighter." *See* "The International Crude Oil Market Handbook," Energy Intelligence Research, 2010, p. A127.

[74] "Medium-Term Oil Market Report," International Energy Agency, July 2007, pp. 54-55.

committed construction projects, which usually take several years to complete, did not see a proportional decrease.[75] According to the IEA, "global refinery crude throughputs have slumped in 2009 in response to weakening oil demand. Market-responsive regions, notably the US, Japan and Europe have seen utilization rates scaled back the most. Less intuitively, significant capacity expansion is expected to continue in the next few years."[76]

C. Increased Capital Expenditure Led to Investment Cost Inflation

42. As the number of planned upstream and downstream capital projects soared, raw materials and labor for oil investment projects were in increasingly short supply, leading to a substantial increase in the cost of those investments. According to EIA's 2006 World Energy Outlook, "[e]xploration and development costs have increased sharply in recent years. In part, rising upstream costs have resulted from higher basic material costs, such as steel and cement. They have also been driven up by a sharp increase in demand for equipment and manpower as companies have sought to boost output in response to higher oil prices. An increase in the number of large-scale projects being developed at the same time, their remoteness and greater complexity and the increasing need for costly production enhancement at large mature fields have added to the upward pressure on cost."[77]

43. Increased investment costs were also experienced in the downstream sector, particularly with respect to the construction of refineries. In 2006, Reuters reported that "[r]ising labor and steel costs are taking some of the shine off U.S. oil refiner plans to spend billions of dollars to expand capacity… The sheer number of new projects … is boosting the cost of new capacity additions as refiners bid up the prices for scarce labor and materials.[78]

44. The 2007 IEA Medium-Term Oil Market Report also noted that refinery projects were subject to "project inflation and slippage similar to that seen in the upstream sector (as a result of

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[75] "Profitability in a world of overcapacity," McKinsey & Company, May 2015, p. 1.
[76] "Medium-Term Oil Market Report," International Energy Agency, June 2009, p. 12.
[77] For example, two of the most expensive locations for drilling in the world are the arctic, and the Sakhalin region in Russia. *See* "World Energy Outlook 2006," International Energy Agency, 2006, pp. 327-31. The latter is not only isolated, but also required very deep drilling. In 2012, a subsidiary of Exxon Mobile drilled the world's longest well there, at 12,376 meters. *See* "Sakhalin-1 Project Breaks Own Record for Drilling World`s Longest Extended-Reach Well", Exxon Neftegas Limited, August 27, 2012.
[78] "Rising costs weigh on US refinery expansion plans," Reuters, November 8, 2006

tightness in the service sector, labor, equipment, and commodity markets)."[79] In a section on refinery construction costs, the IEA report added that

> Refinery expansion plans are increasingly subject to significant cost revisions. Some international (IOC) and national (NOC) oil companies appear to be factoring in cost increases of 30-50% or more, compared with previous estimates for capital budgeting purposes. Furthermore, some greenfield refinery projects have seen bids for the engineering, procurement and construction (EPC) contract at least double the envisaged costs. For example, Kuwait's proposed al Zour refinery was envisaged to cost $6bn by its sponsors, but bids were at least $15bn, or 150% above expectations. This reflects the tightness in EPC markets as order levels for new refining units, project management expertise and raw material costs continue to rise. EPC firms also tend to work for other industries such as power generation, chemical, heavy industries and of course upstream oil and gas. It is noteworthy that many of these other industries are also witnessing a upswing in investment activity further reducing the available pool of resources, not least the human resources necessary for large projects.[80]

45. The IEA further stated that the significant level of investment needed to improve the product quality is one of the root causes of the cost increases in the service sector.[81]

46. Increased costs were not the only consequence of the rush in refinery construction. Another consequence was delay in project completion. The IEA reported that order backlogs had doubled in the 2-3 years prior to 2007, and that the lead times between ordering items and their deliveries had grown significantly.[82]

47. As shown below in Exhibit 4, the Nelson-Farrar Composite Inflation Index, which tracks changes in construction costs in the oil industry,[83] increased steadily by 46 percent from 2000 to 2008. The IHS Downstream Capital Costs Index (DCCI) and the IHS Upstream Capital Costs Index (UCCI), which track costs of equipment, facilities, materials and personnel in the construction of selected geographically diversified portfolios of projects, increased even more

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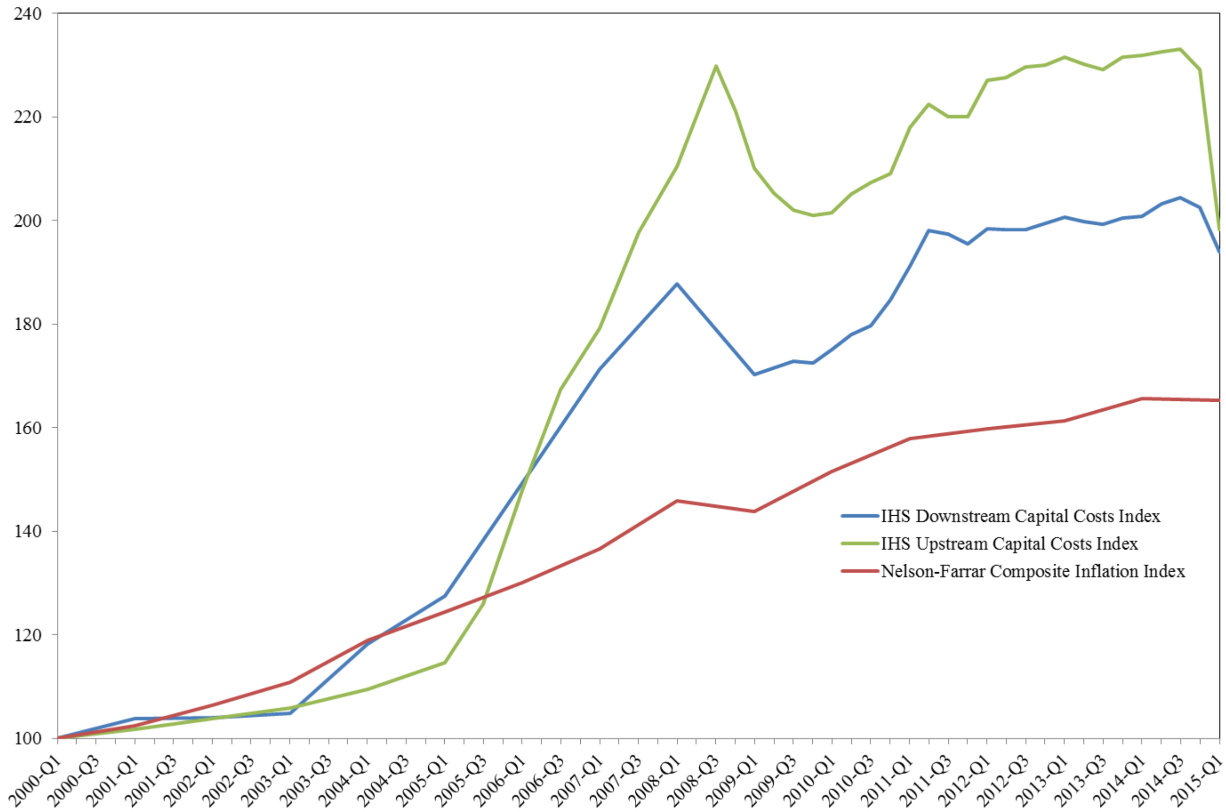
[79] "Medium-Term Oil Market Report," International Energy Agency, July 2007, p. 6.
[80] "Medium-Term Oil Market Report," International Energy Agency, July 2007, p. 56.
[81] "Medium-Term Oil Market Report," International Energy Agency, July 2007, p. 56.
[82] "Medium-Term Oil Market Report," International Energy Agency, July 2007, p. 56.
[83] For details on how the Nelson-Farrar Refining Cost Index is calculated, *see* "How Nelson cost indexes are compiled," Oil & Gas Journal, December 30, 1985.

dramatically, by 88 percent and 110 percent, respectively.[84] In the three years from 2005 to 2008 alone, downstream costs increased by 47 percent and upstream costs increased by 84 percent.[85] Costs were increasing so rapidly during this period, it would have been difficult at the time to reliably estimate market prices for the labor and materials needed for a new refinery project. Construction costs experienced a dip in 2009 (and 2010 for upstream projects), but as explained in Section IV.B, although oil prices and refining margins decreased substantially in the period due to the global financial crisis, construction projects, which can take several years, did not experience a proportional decrease. After 2009, the Nelson-Farrar Composite Inflation Index and the IHS Downstream Capital Costs Index resumed an increasing trajectory in subsequent years. Upstream capital costs resumed their increase after 2011.

[84] Increase calculated as the percentage change between the indices as of 1Q2000 and 1Q2008. The DCCI tracks costs used in the construction of 40 geographically diversified refining and petrochemical projects, while the UCCI tracks costs used in the construction of 28 geographically diversified offshore and onshore pipeline and LNG projects. *See* "Costs & Strategic Sources," IHS Inc., accessed May 9, 2016.

[85] Increase calculated as the percentage change between the indices as of 1Q2005 and 1Q2008. *See* "Costs & Strategic Sources," IHS Inc., https://www.ihs.com/info/cera/ihsindexes/ (last visited May 9, 2016).

Exhibit 4
Oil Industry Construction Cost Indices
2000-2015



Notes:
[1] The Nelson-Farrar Index is calculated annually by taking into account operating labor, construction labor, equipment or materials, instruments, machinery and pipe costs.
[2] The IHS UCCI tracks costs of equipment, facilities, materials and personnel used in the construction of 28 offshore and onshore pipeline and LNG projects. Data for the IHS Upstream Capital Cost Index are available annually through 2005, for Q1 and Q3 in 2005 through 2007, for Q1, Q3 and Q4 in 2008 and quarterly in all years after 2008.
[3] The IHS DCCI tracks costs of equipment, facilities, materials and personnel used in the construction of 40 geographically diversified refining and petrochemical projects. Data for the IHS Downstream Capital Cost Index are available annually through 2008, for Q1, Q3 and Q4 in 2009, and quarterly in all years after 2009.

Sources:
Oil & Gas Journal.
IHS Indexes, IHS Inc., available at https://www.ihs.com/info/cera/ihsindexes/Index.html (last visited May 9, 2016).

48. This increase in construction costs was driven by a multitude of factors, many of which were difficult to anticipate. For example, the IHS attributed high capital costs to rising costs of raw materials and transportation.[86] According to Pritesh Patel, director for Capital Costs Analysis Forum for Upstream, "[t]hese costs are a serious concern and a major challenge for oil and gas companies and are contributing to the delays and postponements of many projects… Exchange

[86] "IHS/CERA Upstream Capital Costs Index: Cost of Constructing New Oil and Gas Facilities Reaches New High," IHS Inc., May 14, 2008.

rate fluctuations and the weakening U.S. dollar also contribute."[87] According to the Associated Press, cost drivers also included a shortage of skilled labor (especially design and project managers), due in part to "the upsurge in offshore exploration and a wave of retirements from baby boomers."[88] Furthermore, the article reported that a shortage of oil rigs and premium pricing for equipment would continue to push capital costs up.[89] Risk Management Magazine reported that volatility in commodities markets were also to blame, stating "[b]etween 2003 and 2008, prices for many of the raw materials used for making industrial products (such as crude oil, steel and aluminum)… rose at double-digit rates only to fall dramatically in the following year… Many manufacturers lack the flexibility to quickly respond to market volatility."[90]

49. Capital investment inflation in the oil industry was therefore a major contributor to cost increases for oil and gas projects worldwide. The IEA's July 2007 *Medium-Term Oil Market Report*, included a 2,600 MBPD downward revision to the 2006-2011 refinery capacity addition forecasts from February that year because "[p]roject slippage caused by cost escalation and lack of spare capacity at engineering contractors and service companies have been so severe…"[91] I describe several example projects affected by this cost inflation in Section V.B.

V. Challenges with Planning and Executing Large Capital Projects

A. Cost Increases and Delays in Megaprojects

50. Cost increases and delays are not uncommon in so-called "megaprojects." Megaprojects are large capital projects that are defined as "large-scale, complex ventures that typically cost US$1 billion or more, take many years to develop and build, involve multiple public and private stakeholders, are transformational, and impact millions of people."[92] For example, according to a study of transportation projects by Professor Brent Flyvbjerg, an expert in project management who studies megaproject execution and outcomes, nine out of ten megaprojects have final costs that exceed even inflation-adjusted budget estimates.[93] In other words, after accounting for the

[87] "IHS/CERA Upstream Capital Costs Index: Cost of Constructing New Oil and Gas Facilities Reaches New High," IHS Inc., May 14, 2008.
[88] "Producing oil, gas more costly, new report says," Associated Press, February 12, 2007
[89] "Producing oil, gas more costly, new report says," Associated Press, February 12, 2007
[90] "The Volatility of Raw Materials Markets," Risk Management Magazine, June 1, 2010.
[91] "Medium-Term Oil Market Report," International Energy Agency, July 2007, p. 54.
[92] Flyvbjerg, Bent, "What You Should Know About Megaprojects and Why: An Overview," Project Management Journal, April/May 2014, p. 6 ("Flyvbjerg (2014)").
[93] The projects in the study span 20 countries and 5 continents. *See* Flyvbjerg, Brent, "Survival of the unfittest: why the worst infrastructure gets built—and what we can do about it," Oxford Review of Economic Policy, Vol. 25, No. 3, 2009, p. 346.

inflation from when a project was budgeted to when it was completed, the final cost of a megaproject almost always exceeds the budgeted amount. It is common for the final cost of these megaprojects to exceed their inflation-adjusted budgets by up to 50 percent. Professor Flyvbjerg estimates that the average cost increases for transportation megaprojects ranged between 20 and 45 percent and finds that cost increases in other industries, including oil and gas, exhibit similar trends. Professor Flyvbjerg's results also exhibit large standard deviations, demonstrating the high degree of uncertainty surrounding cost increases, which lead him to conclude that cost increases of over 50 percent are not uncommon in megaprojects across different industries.[94]

51. Other studies have also documented the prevalence of cost increases in megaprojects across various industries. For example, in a study of over 300 global industrial megaprojects conducted by Edward Merrow of Independent Project Analysis, Inc., a specialist in evaluating capital project management and performance,[95] 65 percent did not meet business objectives related to costs, schedule, and/or planned level of production.[96] The projects that did not meet business objectives had, on average, costs exceeding their inflation-adjusted budget estimate by 40 percent, execution schedules slip by 28 percent, and production in the first year after completion reach only 60 percent of what was originally planned.[97] Approximately 20 percent of the megaprojects included in this analysis were from the oil processing and refining sector.[98] When focusing his analysis on upstream oil and gas megaprojects, Mr. Merrow found that 78 percent

[94] Flyvbjerg (2014), pp. 9-10; Flyvbjerg, Brent, Mette Skamris Holm, and Søren Buhl, "Underestimating Costs in Public Works Projects," Journal of the American Planning Association, Vol. 68, No. 3, Summer 2002, pp. 282-283, 286; Flyvbjerg, Bent, "Survival of the unfittest: why the worst infrastructure gets built—and what we can do about it," Oxford Review of Economic Policy, Vol. 25, No. 3, 2009, p. 346.
[95] Merrow, Edward , "Oil and Gas Industry Megaprojects: Our Recent Track Record," Oil and Gas Facilities, April 2012, p. 42.
[96] Not meeting business objectives is defined as performing below defined thresholds in at least one of five areas: cost overruns, cost competitiveness, slip in execution schedules, schedule competitiveness, and production versus plan. Cost overruns are measured by comparing final costs to estimates made when the project received full-funds authorization. In addition to adjusting for inflation, the analysis adjusts cost overruns for the effect of location and foreign exchange relationships. The projects studied may be biased toward better outcomes than industrial megaprojects in general because they include companies that chose to subject themselves to systematic benchmarking, suggesting they are generally more capable project companies, and data are generally not withheld for projects that go well as compared to projects that do not. *See* Merrow, Edward , *Industrial Megaprojects: Concepts, Strategies, and Practices for Success*, John Wiley & Sons Inc., 2011, pp. vii, 33-38, 48.
[97] Merrow, Edward , *Industrial Megaprojects: Concepts, Strategies, and Practices for Success*, John Wiley & Sons Inc., 2011, p. 48.
[98] Merrow, Edward , *Industrial Megaprojects: Concepts, Strategies, and Practices for Success*, John Wiley & Sons, Inc., 2011, p. 27.

did not meet business objectives–an outcome that was worse than the outcome for industrial projects on average. The upstream megaprojects that did not meet business objectives had, on average, costs exceed the inflation-adjusted budget estimate by 33 percent and execution schedules slip by 30 percent. Moreover, 64 percent of these projects experienced "serious and enduring production attainment problems in the first 2 years."[99] Mr. Merrow found that aggressive schedules and poor or incomplete front-end loading[100] are key drivers of cost increases in upstream oil and gas megaprojects.[101]

52. Another study of upstream megaprojects presented at a 2014 World Economic Forum workshop corroborates these statistics. The study found that for 82 percent of the reviewed projects, current costs exceeded the Final Investment Decision budget by an average of 52 percent. Moreover, 56 percent of the projects experienced schedule overruns averaging 40 percent.[102] Fifty percent of the national oil companies – an oil company where a government is the controlling shareholder – in the sample exceeded the average cost increase observed in the study, compared to only 25 percent of international oil companies and 18 percent of independents,[103] suggesting that national oil companies tend to have even more difficulty implementing these types of megaprojects.

53. Ernst and Young ("EY") also conducted a study of outcomes for oil and gas megaprojects in different industry segments: upstream, midstream (*i.e.*, LNG and pipelines), and downstream (*i.e.*, refining).[104] Across these industry segments worldwide, 64 percent of projects faced cost

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[99] Across all upstream oil and gas megaprojects (both successes and failures), costs exceeded the inflation-adjusted budget estimate by 25 percent, execution schedules slipped by 22 percent, and 45 percent of projects experienced severe and continuing production shortfalls. *See* Merrow, Edward , "Oil and Gas Industry Megaprojects: Our Recent Track Record," Oil and Gas Facilities, April 2012, pp. 38, 40.

[100] Front-end loading is a three-phase process prior to full-funds authorization of a project. Front-end loading includes a first phase to assess the opportunity, a second to develop the project's scope, and a third to define the project. *See* Merrow, Edward, *Industrial Megaprojects: Concepts, Strategies, and Practices for Success*, John Wiley & Sons Inc., 2011, p. 23. This topic is further discussed below in Section VII.

[101] Merrow, Edward, "Oil and Gas Industry Megaprojects: Our Recent Track Record," Oil and Gas Facilities, April 2012, pp. 39-41.

[102] South American projects fared somewhat worse, with 89 percent experiencing cost increases above budgeted amounts (by 46 percent on average), and 67 percent experiencing schedule overruns (by 31 percent on average). *See* "The Future of Oil & Gas Industry Project," World Economic Forum, September 25, 2014, pp. 6-9.

[103] "The Future of Oil & Gas Industry Project," World Economic Forum, September 25, 2014, p. 11.

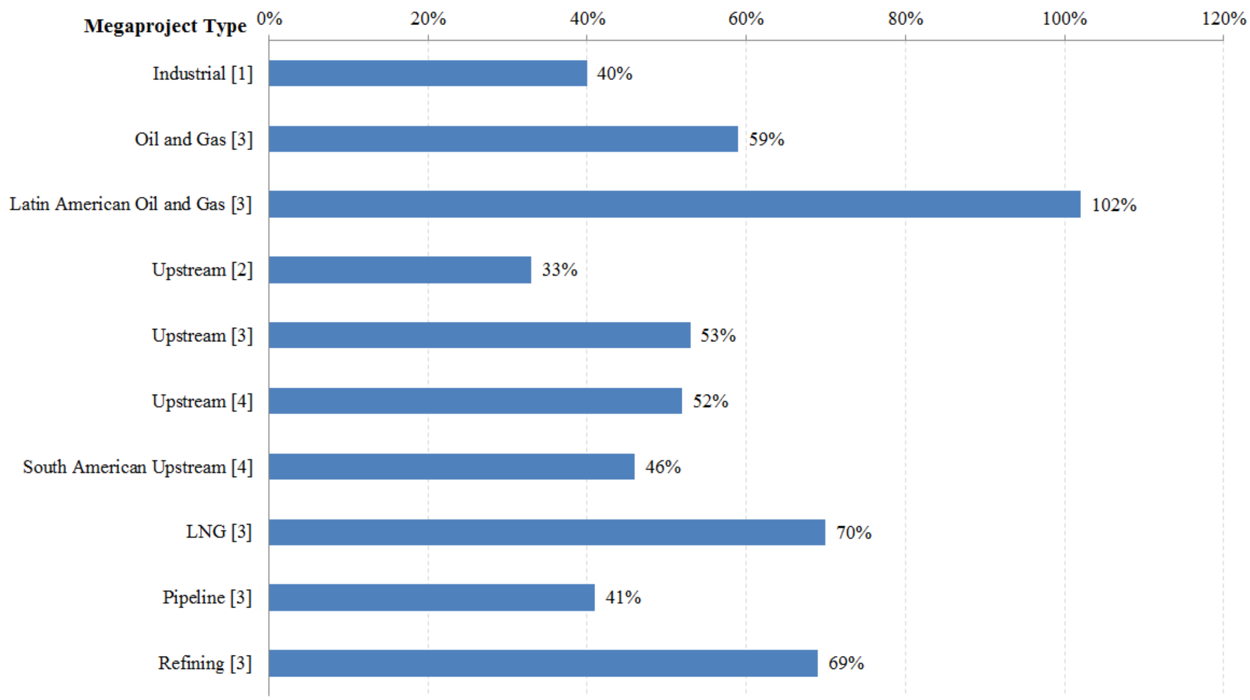
[104] "Spotlight on oil and gas megaprojects," Ernst & Young, 2014, p. 3. *See* Section III.A for an explanation of oil industry segments. LNG stands for Liquefied Natural Gas. Natural gas is cooled to condense it to a liquid, making it more easily transported and stored. After arriving at its end destination,

increases (with average costs being 59 percent above budget) and 73 percent faced schedule delays relative to estimates made during the initial stages of the project's life cycle. These statistics are similar in each industry segment. For refinery projects, 62 percent faced cost increases (with average costs being 69 percent above budget) and 79 percent faced schedule delays. For projects in Latin America, 57 percent faced cost increases, with average costs being 102 percent above budget, and 71 percent faced schedule delays.[105] Cost increases relative to budget and schedule delays are therefore more the rule, rather than the exception, for oil and gas megaprojects, including refinery projects and projects in Latin America. The results of these studies are summarized in Exhibit 5 below.

LNG is converted back into a gas. *See* "Liquefied Natural Gas: Understanding the Basic Facts," U.S. Department of Energy, August 2005, p. 3.

[105] EY's analysis compares a project's current estimated completion costs to initial estimates. Due to this "point-in-time" approach without an assessment of final project costs, it is "possible that cost and schedule delays measured at project completion may be even higher than we report in this paper." EY also analyzed a sample of the largest 20 post-Final Investment Decision projects and found that 65 percent faced cost increases averaging 23 percent above the approved Final Investment Decision budget. *See* "Spotlight on oil and gas megaprojects," Ernst & Young, 2014, pp. 4-6.

Exhibit 5
Average Cost Increases Relative to Budget in Megaprojects



Notes:
[1] Cost increases are taken from Merrow (2011) for projects that did not meet business objectives, and are measured by comparing final costs to budget estimates made when projects received full-funds authorization. Analysis adjusts cost increases for inflation, the effect of location, and foreign exchange relationships.
[2] Cost increases are taken from Merrow (2012) for projects that did not meet business objectives, and are measured by comparing final costs to Financial Investment Decision budget estimates, with both adjusted to the same currency and time base.
[3] Cost increases are taken from EY and are measured by comparing current estimated completion costs to budget estimates made during the initial stages of the project. "Oil and gas" projects include upstream, LNG, pipeline, and refining projects.
[4] Cost increases are taken from the World Economic Forum and are measured by comparing 2014 cost estimates relative to Final Investment Decision budget estimates.

Sources:
Merrow, Edward, *Industrial Megaprojects: Concepts, Strategies, and Practices for Success*, John Wiley & Sons, Inc., 2011, pp. 34-38, and 48.
Merrow, Edward, "Oil and Gas Industry Megaprojects: Our Recent Track Record," Oil and Gas Facilities, April 2012, p. 38.
"Spotlight on oil and gas megaprojects," Ernst & Young, 2014, pp. 4-6.
"The Future of Oil & Gas Industry project," World Economic Forum, September 25, 2014, pp. 6-9.

1. What makes it so difficult for megaprojects to succeed?

54. Megaprojects are inherently risky due to their complexity, long planning horizons, and often unique nature: "[d]elivery is a high-risk, stochastic activity, with overexposure to so-called

'black swans'; i.e., extreme events with massively negative outcomes."[106] According to Professor Flyvbjerg:

> Statistical evidence shows that such complexity and unplanned events are often unaccounted for, leaving budget and timeline contingencies inadequate. […] As a consequence, misinformation about costs, schedules, benefits, and risks is the norm throughout project development and the decision-making process. The result is cost overruns, delays, and benefit shortfalls that undermine project viability during project implementation and operations.[107]

55. As an example, as a member of the board of directors of Valero from 1991 to 1994, I had direct experience with refinery projects that experienced cost increases and delays. One such project was the construction of a 13 MBPD Methyl Tertiary Butyl Ether ("MTBE") plant[108] at Valero's only refinery in Corpus Christi, Texas. The project was estimated to cost $230 million in 1991,[109] and increased to $290 million in 1992,[110] a significant sum given the firm's size and at that time. I recall spending significant amounts of time during board meetings discussing the nature of scheduling the project within the boundaries of the refinery, the delays that occurred, and the cost increases associated with the project, even though Valero contracted with a large engineering construction firm to manage it. In 1994, the *Oil and Gas Journal* stated that a "number of supply disruptions… may tighten U.S. oil and gasoline markets."[111] Around that same time, Valero suspended production of their Corpus Christi MTBE plant, citing depressed MTBE margins and stating that they did not intend to restart production until market conditions improved.[112] Valero entered into another agreement during my time on the board, in 1992, to build a similar 13 MBPD MTBE plant in Mexico. The project was initially estimated to cost $300-350 million,[113] but cost estimates grew to $450 million by 1995.[114] Economic turmoil in Mexico led Infomin, one of Valero's partners, to try to reduce its interest in the project. Citing

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[106] Flyvbjerg (2014), p. 9.
[107] Flyvbjerg (2014), p. 9.
[108] MTBE is used as a fuel component for gasoline in order to raise its oxygen content. *See* "Methyl Tertiary Butyl Ether (MTBE)," U.S. Environmental Protection Agency, https://archive.epa.gov/mtbe/web/html/gas.html, (last visited May 21, 2016); "More oxygenates projects scheduled in U.S.," Oil & Gas Journal, May 27, 1991.
[109] "More oxygenates projects scheduled in U.S.," Oil and Gas Journal, May 27, 1991.
[110] "Petrochem Industry Expands North American MTBE Capacity," Oil & Gas Journal, October 5, 1992.
[111] "OGJ Newsletter," Oil & Gas Journal, December 26, 1994, p. 1.
[112] "OGJ Newsletter," Oil & Gas Journal, December 26, 1994, p. 1.
[113] "Petrochem Industry Expands North American MTBE Capacity," Oil & Gas Journal, October 5, 1992.
[114] Valero Energy Corporation's Form 10-K for the Fiscal Year Ended December 31, 1994, p. 6.

this, the deterioration of the Mexican economy, and the fact that margins for MTBE were "considerably lower than when the Project was conceived," Valero suspended its investment in the plant in 1995, and walked away from the project in 1997.[115]

56. The studies referenced above identify several internal and external factors that are commonly responsible for cost increases and delays in megaprojects. As summarized in Exhibit 6 and discussed in detail below, these factors can be grouped into five broad categories: challenges related to the commercial context of the project, project development challenges, project delivery shortfalls, regulatory challenges, and geopolitical challenges. The first three categories can be described as "Internal Factors" and the last two as "External Factors." Internal factors that cause delays or cost increases are factors that are primarily based on actions or decisions made by firms trying to undertake the megaproject. External factors, on the other hand, are outside the control of the firm undertaking the megaproject.

Exhibit 6
Framework for Evaluating Megaproject Cost Increases and Delays

Internal Factors			External Factors	
Commercial Challenges	**Project Development**	**Project Delivery**	**Regulatory Challenges**	**Geopolitical Challenges**
JV conflict and relationship challenges	Planning challenges - aggressive forecast	Project management issues	Health, safety & environmental risk and local content	Diplomatic security issues
Access to funding	Issues with procurement of contractors	Contractor management issues	Regulatory delay and policy uncertainty	Financial and supplier market uncertainty
Poor portfolio management and changing risk appetite	Issues with estimates and optimism bias	Human capital deficit	Infrastructure challenges	Civil and workforce disruption

Note: Based on framework presented in "Spotlight on oil and gas megaprojects," Ernst & Young, 2014, p. 8.

[115] Valero Energy Corporation's Form 10-K for the Fiscal Year Ended December 31, 1994, pp. 6-7; "Project spurring Mexican scandal was sour deal for Valero, too," San Antonio Business Journal, July 14, 2002.

57. ***Commercial Challenges.*** One of the key commercial challenges faced in the execution of a megaproject is the management of joint venture relationships. Megaprojects are often conducted through joint ventures, particularly when national oil companies are involved in the projects, and the parties often differ in their criteria for evaluating success and tolerance for risk. Commercial challenges can also include funding difficulties, such as the potential for "knee jerk" reactions to financial volatility and complications in risk-sharing between different investors. Additionally, a lack of proper planning can lead companies to develop poorly balanced project portfolios, causing a company's resources to be stretched across uncomplimentary projects or leading a company to be overextended in areas outside the company's areas of expertise.[116]

58. ***Project Development.*** Cost increases and delays also arise from challenges related to the project development process. Inadequate early-stage planning, such as incomplete design, poor front-end loading, and lack of clear project scope that changes over time, can necessitate significant unforeseen changes to the project down the line. These same challenges exist for decisions related to contractor selection and the procurement of materials, particularly given the temptation to base these decisions solely on cost, with insufficient consideration for quality. Optimism bias in the project development process is also a significant factor when considering the likelihood of cost increases and project delays. Over commitment at an early stage can result in systematically underestimated costs and timelines and overestimated benefits.[117] This is even more common for megaprojects that "cross state or national borders and involve a mix of private and government spending."[118]

59. ***Project Delivery.*** Inadequacies in the project delivery process also lead to cost increases and delays. Project management is often very challenging for megaprojects given their size, scale and complexity, and imperfect progress measurements across different independent work streams can have a significant impact on a company's ability to both meet the project's deadline and stay within budget. Megaprojects often also suffer from poor quality materials or service if contractors are not properly supervised throughout the life of the project. All of these internal factors are aggravated by human capital deficits (*i.e.*, lack of experience and scarcity of needed

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[116] "Spotlight on oil and gas megaprojects," Ernst & Young, 2014, p. 9; "The Future of Oil & Gas Industry Project," World Economic Forum, September 25, 2014, p. 14.
[117] "Spotlight on oil and gas megaprojects," Ernst &Young, 2014, p. 9; "The Future of Oil & Gas Industry Project," World Economic Forum, September 25, 2014, p. 14; "Megaprojects: The good, the bad, and the better," McKinsey & Company, July 2015, pp. 4-5; and Flyvbjerg (2014), pp. 9, 11.
[118] "Megaprojects: The good, the bad, and the better," McKinsey & Company, July 2015, p. 3; Flyvbjerg (2014), p. 9.

skills in the face of a steep learning curve for a unique project), particularly in the oil and gas sector, with companies often struggling to find capable employees to execute their complex projects within the original budget.[119]

60. ***Regulatory Challenges.*** On top of the internal challenges inherent to managing megaproject construction are a number of external factors which pose significant road blocks to completing megaprojects on time and on budget. Many of these challenges stem from governmental regulations. Health, safety, and environmental regulations require an increasing amount of attention and resources throughout the life cycle of a megaproject, and governments also often require that a certain percentage of goods and services be sourced locally, regardless of whether the local industry is equipped to meet the project's needs at a reasonable cost. Regulatory delays and bureaucratic hurdles can cause considerable delays throughout the life of a project. Companies also often find it necessary to invest in local infrastructure if the host country's transportation, power, or water sectors are underdeveloped, which can be particularly time-consuming and expensive.[120]

61. ***Geopolitical Challenges.*** External challenges can also present themselves in the form of geopolitical risks or macroeconomic changes. Security threats can lead to significant project delays, and macroeconomic changes to financial markets, commodity pricing, inflation, and exchange rates can have a significant impact on the price paid for necessary raw materials and labor. Access to local labor can also be disrupted by labor strikes or as a result of political unrest, and the cost of labor may increase if the qualified labor pool is small or union negotiating power is strong. All of these external factors are difficult to control or predict, and pose significant challenges to executing megaprojects without delays or cost increases.[121]

62. In the next section I present examples of oil and gas construction projects during the same time period that RNEST and Comperj were being planned and developed, as well as discussion of the challenges faced by national oil companies in particular when pursuing these types of projects. These examples also exhibit many of the same challenges identified in the framework above. In Section VII, I will use this same framework to evaluate the extent to which challenges

[119] "Spotlight on oil and gas megaprojects," Ernst & Young, 2014, p. 10; "The Future of Oil & Gas Industry project," World Economic Forum, September 25, 2014, p. 14; "Megaprojects: The good, the bad, and the better," McKinsey & Company, July 2015, pp. 3, 5; Flyvbjerg (2014), p. 9.
[120] "Spotlight on oil and gas megaprojects," Ernst &Young, 2014, p. 10; "The Future of Oil & Gas Industry Project," World Economic Forum, September 25, 2014, p. 14.
[121] "Spotlight on oil and gas megaprojects," Ernst &Young, 2014, p. 11; "The Future of Oil & Gas Industry Project," World Economic Forum, September 25, 2014, p. 14.

in these five categories were also evident in Petrobras' RNEST and Comperj projects. In this context, the evolutions and outcomes of these Petrobras projects were not surprising.

B. Example Oil and Gas Construction Projects

63. Given the difficulties associated with megaprojects and the influence of market conditions on costs, it is not surprising that substantial cost increases and delays in oil and gas construction projects are commonplace. Major cost increases and delays occurred with several large-scale downstream refinery projects during the 2000s, many of which were constructed by or in partnership with national oil companies. Some of these projects included refineries built or upgraded by sophisticated and experienced companies. A selected example of projects experiencing cost overruns and delays are summarized in Exhibit 7 below.

Exhibit 7
Original and Actual Costs of Oil and Gas Construction Projects ($ Millions USD)

Project Name	Original Cost Estimate	Revised Cost Estimate	Actual Cost	% Cost Increase
Motiva's Port Arthur Refinery	$5,000		$10,000	100%
Saudi Aramco and ConocoPhillips' Yanbu Refinery	$6,000	$12,000	$10,000	67%
IPIC's ConocoPhillips Fujairah Refinery	$5,000	Over $10,000		At least 100%
Tesoro's Martinez Refinery	Over $300		$602	101% maximum
Valero's Quebec City Refinery	$150	$1,800		1100%
Chevron's Gorgon LNG Project	$37,000	$54,000		46%
Kashagan Fields Project	$10,000	$50,000-136,000		At least 400%
Statoil's Mongstad Refinery	$900		$2,200	144%

Note: Cost increase is calculated as the percentage change between the latest reported cost figure and the original cost estimate. The original cost estimate is the estimate at the feasibility study or planning stage, when available. When unavailable, the original cost estimate represents the earliest publicly available estimate.

Sources: News reports, company press releases and filings (see discussion in this section for full details).

64. A particularly noteworthy case involved a joint venture between Shell and Saudi Aramco to expand the Motiva refinery in Texas. The expansion more than doubled the facility's total capacity from 275 to 600 MBPD, making it the largest oil refinery in the U.S.[122] During the planning stage in 2005, the project was originally estimated to cost $5 billion; however, capital investment costs were rising around this time due to changing macroeconomic and industry conditions, such as increases in the cost of labor and steel.[123] Before the end of 2008, Motiva

[122] "Port Arthur Refinery," Shell, http://www.shell.com/about-us/major-projects/port-arthur-refinery.html (last visited May 11, 2016).
[123] "Rising costs weigh on U.S. refinery expansion plans," Reuters, November 8, 2006.

was forced to suspend work for about one year to rein in costs.[124] The refinery became operational in 2012, approximately 2 years behind schedule, and approximately double the original budget at $10 billion.[125] However, after coming online, the refinery suffered from further mishaps – such as chemical leaks and fires – which took the new expansion offline again, creating more delays and further increases in the cost of the project.[126]

65. Similar cases are common around the world. In 2006, Saudi Aramco partnered with ConocoPhillips to build a 400 MBPD refinery in Yanbu, Saudi Arabia, expecting it to become operational in 2011.[127] In its planning stage, the project was estimated to cost $6 billion, but by November 2007 it had climbed to $12 billion, before being revised to $10 billion as of 2010.[128] ConocoPhillips pulled out of the deal in April 2010 amid the increased costs and adverse global economic conditions, which further compounded Yanbu's financial challenges by adding the commercial complication of dealing with a failed joint venture.[129] In March 2011, it was announced that Saudi Aramco had found a new partner, Sinopec, to build the Yanbu refinery.[130] The refinery, which under the new joint venture was renamed YASREF, began operations in January 2015, four years later than originally planned, and at a cost of $10 billion.[131]

66. Yanbu was not the only refinery that faced commercial challenges due to the failure of a planned joint venture. In October 2007, ConocoPhillips pulled out of an agreement to build a 500 MBPD refinery in Fujairah, UAE.[132] According to the feasibility study conducted for the refinery in 2006, it was estimated to cost $5 billion, but by early 2007, estimates had doubled. According to an industry publication, this was attributable to the geopolitical climate, stating "[p]roject costs in the Middle East ha[d] soared as governments [were] spending their oil

[124] "Motiva completes $10 billion Gulf Coast JV refinery expansion," Reuters, May 31, 2012.
[125] "Motiva expansion cost 'in range of' $10 billion: Saudi Aramco CEO," Reuters, May 31, 2012.
[126] "Insight: In hours, caustic vapors wreaked quiet ruin on biggest U.S. refinery," Reuters, June 25, 2012.
[127] "Saudi Aramco and ConocoPhillips Announce Signing of Memorandum of Understanding for Yanbu Export Refinery Project," BusinessWire, May 24, 2006.
[128] "Saudi Aramco, ConocoPhillips: Still Committed to Yanbu," Downstream Today, November 8, 2007; "Conoco Exits Saudi Refinery Venture," Wall Street Journal, April 26, 2010.
[129] "Conoco Exits Saudi Refinery Venture," Wall Street Journal, April 26, 2010.
[130] "Sinopec to Invest in Saudi Refinery," Wall Street Journal, March 17, 2011.
[131] "Yasref continues exports, commissioning activities at Yanbu refinery," Oil & Gas Journal, April 17, 2015; "Saudi Aramco and ConocoPhillips Announce Signing of Memorandum of Understanding for Yanbu Export Refinery Project," BusinessWire, May 24, 2006; Tago, Abdul Hannan, "Major oil accord energizes Riyadh-Beijing partnership," Arab News, January 21, 2016.
[132] "ConocoPhillips Pulls Out of UAE Refinery Project," Downstream Today, October 25, 2007.

revenues on building and expanding industries and infrastructure, leading to a shortage of contractors, raw materials, equipment and qualified labor, which in turn has driven up prices."[133]

67. Cost increases in refining construction projects are certainly not limited to megaprojects. An ostensibly straightforward upgrade of Tesoro's Martinez Refinery, which began in 2006 and was completed in 2008, cost twice as much as originally budgeted. The upgrade involved the construction of a new delayed coker unit, which would allow the refinery to process heavier crude oils. The project was initially estimated to cost over $300 million, while the final price tag was $602 million.[134] According to industry analysts, changes in macroeconomic conditions resulted in higher costs for many refinery projects. In particular, industry analysts pointed to a tight refinery construction labor market as one of the reasons for higher costs.[135]

68. Cost increases also forced Valero Energy to postpone a crude unit expansion (adding 50 MBPD of crude capacity) at its 215 MBPD Quebec City refinery in Canada.[136] As of March 2007, the expansion was estimated to cost $150 million and projected to begin in 2008.[137] This estimate was increased to $900 million in September 2007, and by February 2008 had doubled to $1.8 billion. As of February 2008, the project was postponed.[138] A Citigroup presentation outlining the company's plans noted that "since 2004, the price of steel has risen 74% and heavy-walled reactors are up 133%. In addition, heavy-walled reactor lead times have stretched to 36 months from 12 months."[139] Valero also explained that "Gulf Coast skilled labor costs are up 60%, while productivity is down 35% from 2004 and that lower quality engineering and design result in costly reworks in the field."[140]

[133] "ConocoPhillips Pulls Out of UAE Refinery Project," Downstream Today, October 25, 2007.
[134] "Air District Approves Multi-Million Dollar Upgrade at Tesoro's Golden Eagle Refinery," Bay Area Air Quality Management District, August 31, 2006; Tesoro's 10-K for the Fiscal Year Ended on December 31, 2009, p. 29.
[135] "Rising costs weigh on U.S. refineries," Reuters, November 8, 2006.
[136] Presentation by Bill Klesse, Valero Chairman and CEO, at the Valero Management Presentation, March 27-29, 2007, pp. 14, 18; Oilgram News, Volume 85, Number 61, March 27, 2007, p. 11.
[137] Presentation by Bill Klesse, Valero Chairman and CEO, at the Valero Management Presentation, March 27-29, 2007, pp. 1, 14.
[138] Presentation by Bill Klesse, Valero Chairman and CEO, at the Credit Suisse Energy Conference, February 7, 2008, p. 14; Presentation by Bill Klesse, Valero Chairman and CEO, at the Lehman Brothers Energy/Power Conference, September 5, 2007, p. 12.
[139] Presentation by Bill Klesse, Valero Chairman and CEO, at the Valero Management Presentation, March 27-29, 2007, p. 15.
[140] Presentation by Bill Klesse, Valero Chairman and CEO, at the Valero Management Presentation, March 27-29, 2007, p. 15.

69. The combination of increased capital investment costs, the challenges of managing megaprojects and the many unforeseen roadblocks that are common in the oil industry are also evident in upstream and midstream oil and gas projects, as demonstrated by three recent examples[141]:

- *Shell's Arctic drilling project*: Shell attempted to drill for oil in the Arctic but ran into several hurdles including environmental protests, inability to obtain full drilling permits, ice floes moving into its drill site, oil price expectations, and regulatory restrictions.[142] The project finally was approved by the Obama administration, but still faced the problem of low oil prices and high costs.[143] In September 2015, Shell ended its "expensive and fruitless nine year effort to explore for oil in the Alaskan Arctic – a $7 billion investment – in another sign that the entire industry is trimming its ambitions in the wake of collapsing oil prices."[144]

- *Chevron's Gorgon LNG project in Australia*: This Chevron-operated project is a joint venture between Chevron and ExxonMobil, Shell, and three Japanese utilities.[145] It is one of the world's biggest LNG projects and is expected to produce at least 15.6m tons of gas each year for more than 40 years.[146] According to Chevron's original budget of the project, it was expected to cost $37 billion in 2009, but that estimate grew to $54 billion and as of April 2016 the final cost was expected to be even higher.[147] Delays and budget overruns have been attributed to geopolitical and macroeconomic conditions such as wage increases, low productivity, weather delays, shortages of skilled labor, complexities in project design, and its remote location, among other challenges.[148] According to *The Financial Times*, the project "has faced a difficult birth due to shortages of skilled labour, complexities in design and its very remote location... Those troubles have been

[141] "Top Three Notorious Oil and Gas Megaprojects," The Fuse, April 29, 2015.
[142] "Why Shell Quit Drilling in the Arctic," Bloomberg, September 28, 2015.
[143] "Inside Shell's Extreme Plan to Drill for Oil in the Arctic," Bloomberg, August 5, 2015.
[144] "Shell Exits Arctic as Slump in Oil Prices Forces Industry to Retrench," The New York Times, September 28, 2015.
[145] Smyth, Jamie, "Chevron temporarily shuts down Gorgon LNG project," Financial Times, April 4, 2016.
[146] Smyth, Jamie, "Chevron temporarily shuts down Gorgon LNG project," Financial Times, April 4, 2016.
[147] Klinger, Peter, "Gorgon LNG within weeks of restart," The West Australian, April 30, 2016.
[148] Krauss, Clifford and Stanley Reed, "Shell Exits Arctic as Slump in Oil Prices Forces Industry to Retrench," The New York Times, September 28, 2015; "Chevron temporarily shuts down Gorgon LNG project," Financial Times, April 4, 2016.

compounded by a slump in global gas and oil prices." *The Financial Times* went on to state that the project "is coming on stream at the worst possible time as rival developments in Australia operated by Shell and ConocoPhillips, among others, ramp up production, adding to a global supply glut."[149] Chevron started producing at Gorgon in March 2016,[150] but three weeks after its first shipment, the Gorgon plant was shut down temporarily due to technical difficulties.[151] Chevron announced its plan to relaunch operations as of May 18, 2016, stating that they expected to begin exporting in June or later.[152]

- *Kashagan in Kazakhstan*: A joint project between Eni, BG Group, Statoil, BP, Mobil, Shell and Total was formed in 1993 to explore the northern Caspian Sea. However, over a decade of labor later, regulatory challenges, policy uncertainty and corrosive gasses necessary to exploration resulted in multiple delays and cost overruns. The project was originally estimated to cost $10 billion in 2005, but the total cost has since climbed to somewhere between $50 and $136 billion. As of April 2016, the project was suspended and expected to relaunch in June 2017.[153] According to an industry article, "while Kashagan is emblematic of all that can go wrong at once, it also represents a 'new normal' for an oil industry that is finding itself pushed into riskier political and physical geologies."[154]

70. When government-controlled oil companies pursue ambitious projects independently, the difficulties and risks typically associated with such projects can be magnified.[155] Nevertheless, they attempt such projects in order to achieve energy independence or other equally critical political goals, such as wealth distribution, jobs programs, or economic development. According

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[149] Smyth, Jamie, "Chevron temporarily shuts down Gorgon LNG project," The Financial Times, April 4, 2016.
[150] Press Release, Chevron, "Chevron Achieves First LNG Production at Gorgon," March 7, 2016.
[151] Smyth, Jamie, "Chevron temporarily shuts down Gorgon LNG project," Financial Times, April 4, 2016.
[152] Gloystein, Henning, "UPDATE 1-Australia's Gorgon LNG export facility restarting operations – Chevron," Reuters, May 18, 2016.
[153] "Kashagan oil field to relaunch in June 2017: CNPC vice president," S&P Global Platts, April 22, 2016.
[154] Hayward, Leslie, "Top Three Notorious Oil and Gas Megaprojects," The Fuse, April 29, 2015.
[155] For example, according to the World Bank, "Losses due to inefficiencies may be expected in both the upstream and downstream operations of the NOCs [national oil companies]. Upstream operations attract a lot of attention because of the sheer volume of revenues generated at that level. However, NOC losses frequently appear to be concentrated downstream." *See* McPherson, Charles, "National Oil Companies: Evolution, Issues, Outlook," The World Bank, May 27, 2003, p. 4.

to a Congressional Research Service Report for Congress, international private oil companies were found to be very efficient, while national oil companies "tended to be near the bottom of the rankings." The study found that "Efficiency in producing revenues...is likely affected by the national oil companies' objectives that in general include a greater range of motivating factors than value maximization."[156]

71. One example of a project undertaken by a national oil company under the influence of government interests is the ambitious upgrade of the Mongstad refinery in the 1980s by the state-controlled Norwegian oil company Statoil. The project increased its refining capacity to 145 MBPD and allowed the refinery to process several types of crude oil, including "the heaviest and highest sulfur crude produced in the North Sea."[157] Although Statoil and Norsk Hydro were asked by the government to consider implementing the refinery upgrade jointly, Norsk Hydro, of which the government owned a non-controlling stake, pulled out of the project and pursued foreign refining options which were cheaper and safer.[158] Statoil ultimately pursued the project alone and experienced an estimated $1.3 billion cost overrun with an estimated total cost of $2.2 billion.[159]

72. As discussed in Section III.B, Petrobras' role as Brazil's national oil company meant that the government relied on Petrobras to provide energy independence to the country, which influenced the company's aggressive investment plans. Moreover, despite attempting to pursue joint ventures for RNEST and Comperj, Petrobras was ultimately left to pursue the projects on its own.[160]

VI. Factors Specific to Petrobras and Brazil that Influenced Refinery Costs

A. Petrobras Refinery Construction Experience

73. As of the mid-2000s, Petrobras operated eleven refineries. Of these eleven, nine were built prior to 1972, and the most recent refinery (Henrique Lage, also called Revap) was completed in

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[156] Pirog, Robert, "The Role of National Oil Companies in the International Oil Market," Congressional Research Service Report for Congress, August 21, 2007.
[157] Aalund, Leo R., "Expanded Mongstad Refinery Has Major Export Role," Oil & Gas Journal, March 12, 1990.
[158] Victor, David, David Hults, Mark Thurber, *Oil and Governance*, 2012, p. 638.
[159] *International Petroleum Encyclopedia,* 1989, p. 163. Another source indicates a cost overrun of NOK 6 million of an original budget of NOK 8 million. *See* Victor, David, David Hults, Mark Thurber, *Oil and Governance*, 2012, p. 647.
[160] *See* Section VII.

1980.[161] Thus, prior to evaluating and planning the RNEST and Comperj projects, Petrobras had not built a refining facility from the ground up, referred to as a greenfield or grassroots refinery, for approximately twenty-five years.

74. Furthermore, Petrobras' refineries were all built prior to the discovery of Brazil's heavy crude oil resources, and thus the refineries were originally designed to process imported light sweet crude oil.[162] Though Petrobras retrofitted their refineries throughout the 1990s and early 2000s in order to be able to process Brazil's heavier crude,[163] Petrobras had no recent experience designing and building a grassroots facility for processing crude when it embarked on the RNEST and Comperj projects. A grassroots refinery project, in particular one being built to process heavy crude, is considerably more complicated and thus at greater risk for unanticipated costs and delays relative to upgrading or expanding an existing facility, especially given Petrobras' lack of recent experience with such an endeavor.[164] The RNEST and Comperj projects were therefore even more susceptible to increasing costs and other challenges associated with oil and gas megaprojects.[165]

75. In addition to embarking on plans to construct grassroots refineries, Petrobras continued its program of upgrading and expanding existing refineries from the mid-2000s through the present. By the end of 2014, thanks to upgrade projects, all of Petrobras' refineries were capable of producing a maximum sulfur content for diesel of 500 ppm (parts per million), and nine

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[161] Petrobras' Form 20-F for the Fiscal Year Ended on December 31, 2005, p. 44-45.
[162] Petrobras' Form 20-F for the Fiscal Year Ended on December 31, 2005, p. 44.
[163] *See* Petrobras' Form 20-F for the Fiscal Year Ended on December 31, 2005, p. 44; "Petrobras implements $29 million refining-technology program," Oil and Gas Journal, March 22, 1999; "Gabriel Passos (Regap)," http://www.petrobras.com.br/en/our-activities/main-operations/refineries/gabriel-passos-regap.htm (last visited May 25, 2016); "Alberto Pasqualini (Refap)," http://www.petrobras.com.br/en/our-activities/main-operations/refineries/alberto-pasqualini-refap.htm (last visited May 25, 2016).
[164] For example, the National Petroleum Council notes "[t]he absence of grassroots domestic refinery construction indicates the relative attractiveness of expanding or acquiring existing refineries compared with building a new refinery. Refinery construction at a new site would require very long planning, site selection, permitting, financing, and construction lead times. Expansion, acquisition, and increased utilization of existing refineries are typically more feasible, quicker, and less costly options…" *See* "Observations on Petroleum Product Supply," National Petroleum Council, December 2004, p. I-19.
[165] For example, analysts from Barclays Capital noted that "the cost of constructing new refineries in Brazil appears to be significantly higher than the previous approach" of "buying and upgrading simple international refining assets to provide outlets for the rising heavy oil production." *See* Cheng, Paul Y., Christina Cheng, and Danielle Diamond, "Downgrade to 2-EW," Barclays Capital, October 6, 2010, pp. 3-4.

refineries could produce 10 ppm sulfur diesel.[166] Certain Petrobras refineries also underwent extensive modernization projects during the same time period.[167] Pursuing these capital-intensive projects simultaneously with the RNEST and Comperj projects almost certainly exacerbated the effects of increasing development costs in the oil and gas industry in general (described above), as well as escalation of costs in Brazil in particular (discussed in the next section).

B. Factors Specific to Brazil in 2006-2014

76. The Expert Report of Sebastian Edwards, dated May 27, 2016 ("Edwards Report") discusses a number of factors that contributed to increased costs of large-scale construction projects in Brazil during the 2006 to 2014 period. These factors include a tight labor market and increasing costs of labor, a construction boom in Brazil during this period, protectionist policies of the Brazilian government (in particular, local content requirements), and a global commodities boom accompanied by increasing commodity prices. Moreover, the interaction of these factors further exacerbated cost increases for large-scale construction projects in Brazil during this period.[168] Given the confluence of these factors in Brazil, it would not have been surprising that RNEST and Comperj experienced cost significant increases.

VII. Petrobras' RNEST and Comperj Investments

77. Petrobras began evaluating the potential construction of RNEST and Comperj in the early to mid-2000s. As discussed briefly in Section III.B and in detail in the Edwards Report, this period of Brazil's history was characterized by government policy that emphasized infrastructure

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[166] Petrobras' Form 20-F for the Fiscal Year Ended on December 31, 2013, p. 38. Other improvements focused on refineries' abilities to produce low sulfur gasoline in addition to diesel, from 1,000 ppm to 50 ppm. *See* Petrobras' Form 20-F for the Fiscal Year Ended on December 31, 2012, p. 36. Regulations targeted at reducing tailpipe emissions have focused on the quantity of sulfur and other contaminants (such as nitrogen and metal contaminants) contained in vehicle fuel (typically measured as the volume of contaminate present per million equivalent volume parts of the fuel mixture). When fuel is combusted these contaminants are vented with the vehicle exhaust as various sulfur oxides, nitrogen oxides, and other volatile organic compounds or particulate matter causing health and environmental concerns. Reducing the quantity of these contaminants in the original fuel thus reduces vehicle emission pollution levels. *See* "Particulate Matter (PM) – Basic Information," U.S. Environmental Protection Agency, https://www3.epa.gov/pm/basic.html (last visited May 26, 2016); "Particulate Matter (PM) – Reducing Particle Pollution," U.S. Environmental Protection Agency, https://www3.epa.gov/pm/reducing.html, (last visited May 26, 2016).

[167] *See* "Gabriel Passos (Regap)," http://www.petrobras.com.br/en/our-activities/main-operations/refineries/gabriel-passos-regap.htm (last visited May 25, 2016); "Potiguar Clara Camarão," http://www.petrobras.com.br/en/our-activities/main-operations/refineries/potiguar-clara-camarao.htm (last visited May 25, 2016).

[168] These factors are discussed throughout the Edwards Report and are summarized in Section 4. In particular, *see* ¶ 4.7.

investment as a tool for driving economic growth. This policy included investment in energy infrastructure, including modernizing oil refining, with the overarching goal of energy independence. In addition, Brazil's history of price controls on oil and refined products may have discouraged foreign investment in refining in Brazil.[169] As a result, Petrobras was seen as a key tool for driving economic investment and development, including increasing refining capacity in Brazil.[170] Petrobras' decision to construct additional refining capacity can therefore be attributed in part to Brazil's policies directed towards achieving energy independence, and the socioeconomic and political desire to spur economic growth through capital projects.[171]

78. Plaintiff expert Steven Henning alleges, "the flaws in Petrobras' competitive bidding process and the clear trend of overbilling on the capital improvement projects [including RNEST and Comperj] cannot be ignored," and that "[t]here is no doubt that Petrobras executives had knowledge of these pervasive issues as early as 2009."[172] These allegations must be assessed within the full framework of the planning, budgeting, and implementation of these projects, as well as considering contemporaneous developments in the oil industry and in Brazil.[173] In this section, I review the multi-phase planning and implementation process used by Petrobras for RNEST and Comperj. The project development phases and accompanying cost estimates are summarized in Exhibit 8 below.

[169] Edwards Report, ¶ 3.1.
[170] Sequeira, Marcus, "Lowering PT on short-term concerns and higher capex," Deutsche Bank, June 30, 2010, pp. 3, 5.
[171] Petrobras Form 20-F for the Fiscal Year Ended December 31, 2014, pp. 26-27; Yang, Lilyanna, "Meeting Downstream – Reiterate Neutral," UBS, November 22, 2010, p. 3.
[172] Expert Report of Steven Henning, dated May 6, 2016 ("Henning Report"), pp. 1-32.
[173] *See* Sections III.B, IV and VI.B.

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79. Petrobras' planning and design process is consistent with standard industry practice. Most commonly, the assessment and planning for these projects is broken up into a three-phase process, referred to as front-end loading, prior to full-funds authorization of a project. The front-end loading phases include a first phase to assess the opportunity, a second to develop the project's scope, and a third to define the project. After the completion of these phases, the project is evaluated for funds authorization after which the actual execution of the project begins.[174]

80. The first phase is typically "devoted to the development of the business case and sorting out the basic feasibility of a capital investment" and may assess several potential projects to guide

[174] Merrow, Edward, *Industrial Megaprojects: Concepts, Strategies, and Practices for Success*, John Wiley & Sons, Inc., 2011, p. 23.

selection of a few key options for further assessment.[175] **Commercially Sensitive**

81. The second phase is typically described as the "scope selection and development phase of a project" and involves a full conceptual detailing of the project. This phase can provide the first reliable cost estimate for the project, but the reliability of the estimate depends heavily on the completeness with which the project's scope is developed.[178] **Commercially Sensitive**

82. Finally, the third phase typically requires sufficient technical engineering, "to the point that execution can proceed without changes."[180] This level of precision in engineering and design is often very costly, and typically even more so for megaprojects. Consequently "very few projects are halted" once they begin this phase.[181] **Commercially Sensitive**

[175] Merrow, Edward, *Industrial Megaprojects: Concepts, Strategies, and Practices for Success*, John Wiley & Sons, Inc., 2011, p. 24.
Commercially Sensitive

[178] Merrow, Edward, *Industrial Megaprojects: Concepts, Strategies, and Practices for Success*, John Wiley & Sons, Inc., 2011, p. 25.
Commercially Sensitive

[180] Merrow, Edward, *Industrial Megaprojects: Concepts, Strategies, and Practices for Success*, John Wiley & Sons, Inc., 2011, pp. 25-26.

[181] Merrow, Edward, *Industrial Megaprojects: Concepts, Strategies, and Practices for Success*, John Wiley & Sons Inc., 2011, pp. 25-26.
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83. In analyzing the evolution of the expected costs of these projects, it is important to keep in mind the evolution of the project phases, from less precise estimates (generated at the end of Phase I and Phase II) to more precise project execution budgets (generated at the end of Phase III), as described above. In addition, it is important to recall the economic context of increasing costs for oil and gas projects during the 2000s (*see* Section IV) and the challenges typically associated with oil and gas megaprojects (*see* Section V).

84. In evaluating the development of the RNEST and Comperj projects, I apply the framework presented in Section V above to evaluate the various causes of budget revisions, cost increases, and delays experienced by Petrobras' projects relative to those commonly experienced by similar types of projects. My findings are summarized in Exhibit 9 below.

Exhibit 9
Framework for Evaluating Megaproject Cost Increases and Delays: Factors Impacting Petrobras' RNEST and Comperj Projects

Internal Factors

Commercial Challenges	RNEST	Comperj
JV conflict and relationship challenges	X	X
Access to funding		
Poor portfolio management and changing risk appetite		

Project Development	RNEST	Comperj
Planning challenges - aggressive forecast	X	X
Issues with procurement of contractors	X	X
Issues with estimates and optimism bias	X	X

Project Delivery	RNEST	Comperj
Project management issues	X	X
Contractor management issues	X	X
Human capital deficit	X	X

External Factors

Regulatory Challenges	RNEST	Comperj
Health, safety, & environmental risk and local content	X	X
Regulatory delay and policy uncertainty		X
Infrastructure challenges	X	X

Geopolitical Challenges	RNEST	Comperj
Diplomatic security issues		
Financial and supplier market uncertainty	X	X
Civil and workforce disruption	X	X

85. Consistent with other oil and gas megaprojects, both RNEST and Comperj experienced significant challenges in each of the categories identified with an "X," including substantial changes in scope and design and increasing development costs in the industry and in Brazil, throughout the evolution of these projects starting from the early phases. The result was that cost estimates had to be revised upwards due to the combination of project-specific and industry factors. As the projects entered the execution phase, against this backdrop of continuously increasing cost estimates, subsequent cost increases reasonably could have been seen as a continuation of the process that resulted in the prior cost increases.

86. In the remainder of this section, I provide a detailed assessment of the evolution of the RNEST and Comperj projects and the challenges they faced.

A. Abreu e Lima Refinery (RNEST)

1. Introduction

87. Petrobras began evaluating the possibility of building RNEST in Commercially Sensitive

Furthermore, as discussed in Section III.B, Petrobras was particularly motivated by the Brazilian political agenda of energy independence, and the program became included in PAC (Brazil's Growth Acceleration Program).[187]

88. As this project moved beyond assessment (Phase I) and conceptual design (Phase II) into basic engineering (Phase III) and implementation (Phase IV), the estimated cost for the project was revised upwards significantly relative to initial estimates and the timeline for the project was extended. A portion of these upward revisions can be attributed to the design of the project which also changed significantly as the planning process progressed. The changes to RNEST's conceptual design are illustrated in Exhibit 10. While the specifics of the redesign are explained in more detail in the following sections, in brief, the changes to RNEST's design Commercially Sensitive

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[187] "Petrobras Form 6-K, "Main Petrobras Projects in the Growth Acceleration Plan (GAP)", January 23, 2007.

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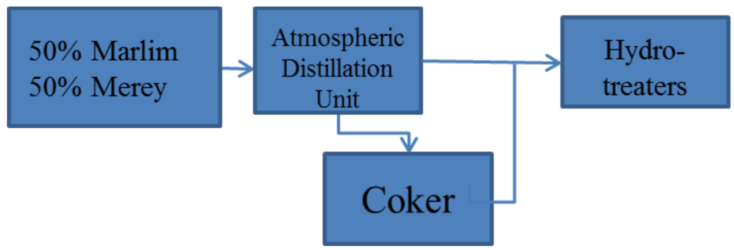
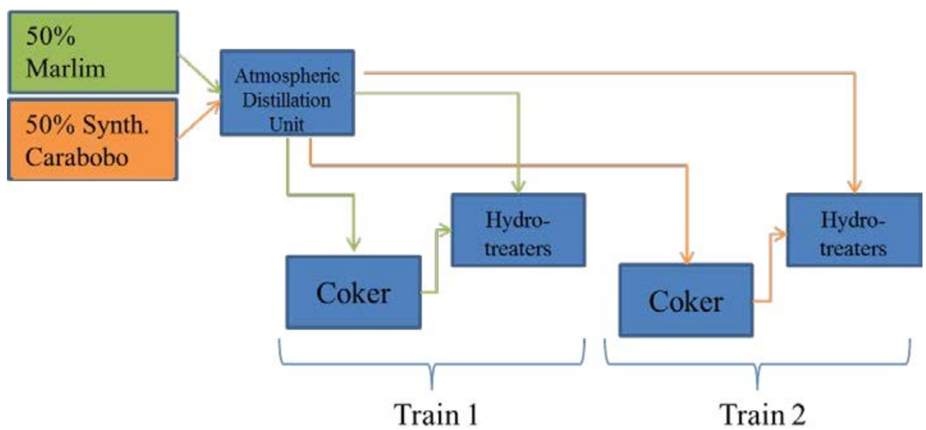
Exhibit 10[188]
Illustration of RNEST Changes in Design and Scope

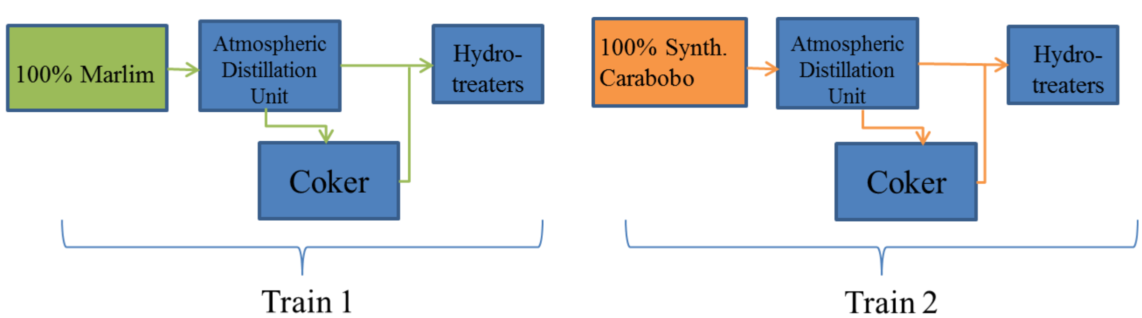
Phase I: Assessment of opportunity (2005)
RNEST consisted of a single refinery train with a capacity of 200 MBPD



Phase II: Conceptual Design (2006)
RNEST consisted of two dependent refinery trains (each with a capacity of 100 MBPD) with a single, shared atmospheric distillation unit



Phase III: Basic Engineering (2007-2009)
RNEST consisted of two entirely independent refinery trains (each with a capacity of 115 MBPD)



89. As I discuss in detail below, these revisions to the project's scope, in addition to project management decisions and the macroeconomic context encompassing the construction, all

[188] RNEST 2014 Presentation, p.17.

contributed to Petrobras' series of revised estimates for the project's cost. Exhibit 11 summarizes the principle drivers of the revised estimates as the project progressed through the planning phases.

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90. As no bids had been invited during Phase I or Phase II, there exists no plausible rationale to the plaintiffs' claim that changes in scope or preliminary cost estimates that occurred as the project moved into Phase III could have alerted Petrobras' senior management to any possible corruption with respect to bidding or contracting. As the project moved into Phases III and IV, the same factors that typically affect megaprojects continued to drive cost estimate revisions upward. Against this backdrop of changing project scope and shifting economic circumstances, which would likely have appeared to account for the increases in the project's estimated cost, it would be unreasonable to conclude that members of Petrobras' senior management could or should have been able to identify a relatively small fraction of such increase in total costs allegedly attributable to overcharging by contractors.

2. Phase I: Assessment of Opportunity Commercially Sensitive

91. The basis for Petrobras' initial estimate of the cost of RNEST was a "Phase I" feasibility assessment of the potential project conducted Commercially Sensitive

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93. **Commercially Sensitive**

3. Phase II: Conceptual Design (March – November 2006)

94. During 2006, Petrobras completed the conceptual design of RNEST (Phase II), which included high-level engineering assessments. As discussed previously, the intention of Phase II is to better define the scope of the project and develop the conceptual design.[198] RNEST's Phase II cost estimate reflected new information about anticipated inputs for the refinery and market conditions, as well as a more detailed review of what the project would require. At the time Phase II was completed, Petrobras had still not solicited any bids for contracts of the project's

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[198] RNEST 2014 Presentation, p. 15.

components. The result of the Phase II analysis, as of Petrobras' completed report dated December 20, 2006, was a revised cost estimate for RNEST of US $4.056 billion.[199]

95. **Commercially Sensitive**

However, the synthetic Carabobo crude oil ultimately presented even more challenges for the design of RNEST as is discussed in the following section.[205]

96. Simultaneously, macroeconomic factors were affecting the estimated cost of RNEST. For instance, changes in the exchange rate between the U.S. dollar and the Brazilian Real (*i.e.*, due to

[199] RNEST EVTE II 2006, p. 306.
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the appreciation of the Real), increased the cost of the project as expressed in U.S. dollars by approximately US $357 million relative to the Phase I estimate.[206] Furthermore, the market for construction was heating up (*i.e.*, experiencing high demand), both domestically from competing major capital projects in Brazil, and internationally as other oil companies also scrambled to increase capacity to meet market demands (*see* discussion in Section IV). Petrobras attributed an additional US $869 million in cost estimates to the increased prices of construction materials and labor.[207]

97. Petrobras continued to plan the refinery units and proposed the possibility of contracting some components of the refinery work prior to completing the basic engineering design in Phase III. In the Phase II report, Petrobras noted that in order to maintain the necessary schedule for the refinery's target startup in 2011, some components of construction would need to begin while the Phase III engineering design work was still in progress.[208] The components suggested for advancement ahead of basic engineering included site preparation contracts (such as earthworks and the relocation of pipes and power lines), contracting unit orders for key equipment with long delivery times, and contracting for engineering design and the construction of necessary infrastructure components including water treatment and power generation units.[209]

98. The proposal to advance contracting for these components of the project was formalized and approved in Petrobras' Refinery Anticipation Plan ("PAR") in March 2007, shortly after the conclusion of Phase II.[210] The objective of PAR was to accomplish the proposed timeline for completion of RNEST by pre-ordering "the necessities."[211] In the months between the completion of Phase II and the Executive Board's review of PAR, additional equipment and key units were reclassified as critical and the prices quoted for these critical units reflected the strict timeline anticipated for their delivery and installation.[212] The PAR even discussed the possibility that RNEST might begin operations as early as 2010, though it also warned that the proposed

[206] RNEST EVTE II 2006, p. 306. *See* full discussion of exchange rates and fiscal challenges in Section 2 of the Edwards Report.
[207] RNEST EVTE II 2006, p. 307.
[208] RNEST EVTE II 2006, p. 3010.
[209] The Phase II report proposed beginning the procurement process for critical equipment with supply periods longer than 500 days, including coke drums, reactors, high pressure exchangers, centrifugal compressors, and reforming furnaces, as early as January 2007. *See* RNEST EVTE II 2006, p. 3010.
[210] RNEST CIA Report, pp. 5-6.
[211] "Plan of Anticipation of the Northeast Refinery," AB-CR 97/2008, March 18, 2008, p. 5.
[212] "Plan of Anticipation of the Northeast Refinery," AB-CR 97/2008, March 18, 2008, pp. 2-3.

timeline included no safety margin.[213] Petrobras' own internal review of the RNEST construction process identified PAR as a significant contributor to the increased expense of the project. For instance, following the PAR approval, Petrobras executed contracts for several components of work including earthworks on July 31, 2007, despite the fact that "the basic project was [still in] the final stage of revision."[214] Furthermore, subsequent changes in the basic engineering design of RNEST occurred after the approval of PAR, affecting the required units for the refinery and "[making] it difficult to reach the PAR objectives as the basic project was not sufficiently defined" at the time PAR was approved.[215]

4. Phase III: Basic Engineering Commercially Sensitive

99. As Petrobras' Phase III engineering work for RNEST progressed, Commercially Sensitive

In addition, previous deficiencies in Petrobras' cost estimations were revealed. Internal presentations and public disclosures during this period presented corrections to the previously announced estimates generated during Phase II. Commercially Sensitive

100. As a result of the PAR's approval, by the time the basic engineering report for Phase III was finalized Commercially Sensitive

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[213] RNEST CIA Report, p. 5; "Plan of Anticipation of the Northeast Refinery," AB-CR 97/2008, March 18, 2008, p. 44.

[214] RNEST CIA Report, p. 5.

[215] RNEST CIA Report, pp. 5-6.

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[217] "RNEST Project Revision," Petrobras AB-CR/PP, July 2, 2009 (PBRCG_00334236) ("RNEST Project Revision"), p. 3

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of Phase III.[221] As in Phase II, the refinery was still expected to begin operations in 2011.[222] Identified causes for the increase in estimated cost were similar to the common causes for cost increases of other oil and gas megaprojects.[223] Also, similar to Phase II (which was prior to any contracting), during Phase III the project continued to encounter significant project development shortfalls and geopolitical challenges. In addition, as construction began, shifting the project from a development phase into a delivery phase, additional project delivery shortfalls, regulatory challenges, and joint venture conflicts were experienced. For each of these five categories of common causes of cost increases, I discuss below specific examples that were present during Phase III of RNEST.

101. The change in cost estimates throughout the previous phases for RNEST reflected in large part the uncertainly of the project's scope and thus the necessity to redesign and rework engineering plans. Similar challenges, including project development shortfalls continued to affect the estimated cost of RNEST in Phase III as well. In August 2009, Petrobras publicly stated that the basic engineering work conducted from 2007-2009 as part of Phase III generated an updated investment profile that could be attributed to "better definition of the units' technical scope, the improved knowledge regarding the characteristics of the oil to be processed, in addition to the analyses made of the results obtained in refining simulations, [which] allowed the processing capacity to be resized and the refinery's technical and economic performance to be optimized."[224] For example, during Petrobras' Phase III design work, in December of 2007, tests on the Venezuelan oil were finalized, and the results indicated that it would be impossible to process the improved Carabobo 16 crude with the Brazilian oil in a single atmospheric distillation unit. Accordingly, RNEST had to be redesigned again to operate two entirely separate refining trains (*see* Exhibit 10).[225] In addition, the intended capacity of the project was increased from the initial 200 MBPD reflected in the Phase I and II estimates, to 230 MBPD (consisting of 2 units each with a capacity of 115 MBPD).[226]

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commitments were "related to the processes of critical equipment purchase, contracts in progress, agreements and other management and support costs." *See* RNEST EVTE III 2009, p. 2.

[221] Project for Implementation of Northeast Refinery, PBRCG-P_01344576_000011; RNEST EVTE III 2009, p. 2.

[222] Project for Implementation of Northeast Refinery, PBRCG-P_01344579_00002.

[223] *See* Section V.A.

[224] Petrobras Form 6-K, "Clarification about News: Abreu e Lima Refinery," August 27, 2009, p. 2.

[225] RNEST CIA Report, p. 7.

[226] Project for Implementation of Northeast Refinery, PBRCG-P_01344576_00002, 6.

102. These design changes made it necessary to order additional equipment components, and in some cases required revising contracts that had already been negotiated and finalized.[227] For instance, the contract for front-end engineering design of on-site and off-site components for the refinery was signed in March of 2008 as a PAR initiative. Petrobras' internal review of the process concluded that the expense of this work was adversely affected by the number of changes to the project after contracting, "caused by the lack of basic projects' maturity and by the absence of technical specifications for materials and equipment that were acquired." Petrobras concluded that these reasons were "the main motivators to the contractual addendums," which were required to complete the front-end engineering design work, and that advanced contracting had not proven itself to be a good strategy.[228] In addition, Mr. Marco Aurelio, the Executive Manager of Materials for Petrobras testified during Petrobras' internal investigation that he received purchase orders for four main equipment components (including reactors, furnaces, coke drums, and turbogenerators) at the end of 2007.[229] However, the specifications for these units had to be altered during the purchase process which had "a negative impact on the condition of the processes."[230]

103. Geopolitical challenges also continued to affect the project through changes in financial and supplier markets. The years between Phases II and III experienced similar inflation, tightening of the construction market and consequent cost increases that were experienced in the years between Phases I and II. On August 27, 2009, Petrobras announced that the increase in price reflected in revised estimates was attributable to "a significant surge in equipment and service prices compared to the original estimates on account of a cost inflation in the oil industry as a result of the spike in international oil prices in the past few years and, a less expensive Dollar compared to the Real, which increases the costs incurred in Reals, in which most of the cost is denominated."[231]

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[227] Additional necessary equipment included a desalinization unit, lower pressure vessel systems, coolers, and purification systems. *See* RNEST CIA Report, p. 7.
[228] "RNEST CIA Report Addendum" (PBRCG_00161497), p. 8.
[229] RNEST CIA Report, p. 7.
[230] RNEST CIA Report, p. 7.
[231] Petrobras Form 6-K, "Clarification about News: Abreu e Lima Refinery," August 27, 2009, p. 2.

All of these indicated drivers of Petrobras' revised cost estimate were reasonable and consistent with the market conditions globally and in Brazil at this time.

104. Project delivery shortfalls experienced during this phase of RNEST can be categorized as ineffective project management and poor contractor management, each of which lead to additional delays and cost increases for the project. For example, the Suape region experienced an extended rainy season which delayed the necessary earthworks, such that it was not completed during the contracted period.[235] Due to the weather delays the contract lapsed with the earthworks still incomplete, which in turn slowed the possible progress of other construction at the site.[236] In addition, Petrobras acknowledged that the complexity of the project led to the contracts becoming consolidated among a limited number of suppliers, reducing bargaining leverage and competition.[237] The volume of contracts also required significant coordination, management, and oversight from Petrobras which taxed internal resources.[238] Furthermore, Petrobras sought to contract with Brazilian suppliers as a result of self-imposed local content requirements. Petrobras therefore decided to provide smaller firms with opportunities to bid on contracts.[239] This decision added to the risk of increasing costs and delays for the project.[240]

As stated in Section 4 of the Edwards Report, "Wages of engineers increased by 34% from February 2007, when these data are first available, to September 2009, while wages of semi-skilled workers increased by 23% over this same period." *See* Edwards report, ¶4.12.

[235] Typical rainy season is from March through August, but during 2008 and 2009 this season "extended beyond expectations." *See* "Project for Implementation of Northeast Refinery," September 3, 2009 (PBRCG-P_01344576), PBRCG-P_01344576_00008; "RNEST Project Revision," Petrobras AB-CR/PP, July 2, 2009 (PBRCG_00334236), pp. 7, 11-12.

[236] "Project for Implementation of Northeast Refinery," September 3, 2009 (PBRCG-P_01344576), PBRCG-P_01344576_00008.

[237] "RNEST Project Revision," Petrobras AB-CR/PP, July 2, 2009 (PBRCG_00334236), pp. 7, 13.

[238] "RNEST Project Revision," Petrobras AB-CR/PP, July 2, 2009 (PBRCG_00334236), pp. 7, 13.

[239] For instance, a UBS analyst report indicated that "the rationale for some investments have been job creation in the less developed Northeast states and use of many small contracting companies so as to help develop the local economy." Yang, Lilyanna and Carlos Herrera, "Lower PT w/ c.30% EPS cut post-3Q14 delays, CEO/CFO call, and Brazil oils trip – Buy the PNs," UBS, November 18, 2014, pp. 13-14.

[240] Sequeira, Marcus, "Lowering PT on short-term concerns and higher capex," Deutsche Bank, June 30, 2010, p. 12; Cheng, Paul Y., Christina Cheng, and Danielle Diamond, "Downgrade to 2-EW," Barclays Capital, October 6, 2010, p. 3; Edwards Report, Section 3.B; RNEST Project Revision, p. 13.

105. Regulatory challenges were also partially responsible for the increase in cost estimates reflected in the final Phase III report. First, in addition to the redesign that was necessary to process PDVSA's crude oil, design changes had to be implemented to meet requirements imposed by new environmental regulations that were approved between 2008 and 2009.[241] When the project was proposed, the intention was to maximize diesel production with an allowed quality of 50 ppm for sulfur.[242] However, by July 2009, new legislation to adopt European standards was being considered, such that Petrobras now anticipated a change in the quality standard reducing sulfur content to 10 ppm starting in January 2013.[243] On August 27, 2009 Petrobras announced that the increase in price reflected in the revised estimate was attributable in part to "an increase in the project's scope intended to increase refining capacity and include new systems to improve product quality."[244] Secondly, the lack of sufficient infrastructure for the site continued to impose additional cost burdens on Petrobras.[245] Petrobras was asked on an earnings call why RNEST was expected to cost more than comparable refineries in Europe and the EU, and responded that whereas most refineries can simply be plugged into existing infrastructure, Petrobras had to develop part of the necessary infrastructure around RNEST including "power generation, power distribution, the utilization of residuals, [and] transportation."[246] Petrobras stated that these "off-site" costs for RNEST were far more significant than the off-site costs incurred by firms building refineries in areas where infrastructure existed.[247]

106. Finally, Petrobras reassessed its potential partnership with PDVSA during Phase III and determined that, given the difficulties and additional expenses caused by the partnership, "the implementation of the project through a partnership proves to be unfavorable for Petrobras."[248] Though the potential partnership with PDVSA had been discussed extensively,[249] and Petrobras had demonstrated its commitment to the partnership by investing in PDVSA's Carabobo oil field

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[241] "Conama Resolutions: 1984 – 2012 Special Edition," National Environment Council, pp. 537 - 548; RNEST 2014 Presentation, p. 12.

[242] Petrobras Form 20-F for the Fiscal Year Ended on December 31, 2008, p. F-71-72.

[243] RNEST Project Revision, p. 15; "Worldwide Emissions Standards," Delphi, 2015-2016, p. 42; "Directive 2003/17/EC of the European Parliament and of the Council of 3 March 2003 amending Directive 98/70/EC relating to the quality of petrol and diesel fuels," EUR-Lex. *See also* discussion of environmental regulations during this time in Section IV.

[244] Petrobras Form 6-K, "Clarification about News: Abreu e Lima Refinery," August 27, 2009, p. 2.

[245] Leite, Emerson, Marcos Guerra, and Vinicius Canheu, "Petrobras Reinstatement: Stronger asset base, diluted investment case," Credit Suisse, October 12, 2010, pp. 23, 25.

[246] Petrobras Q4 2009 Earnings Call, March 24, 2010, pp. 7-8.

[247] Petrobras Q4 2009 Earnings Call, March 24, 2010, p. 8.

[248] Project for Implementation of Northeast Refinery, PBRCG-P_01344576_000019.

[249] Petrobras Form 20-F for the Fiscal Year ended on December 31, 2006, pp. 66-67.

at a 40 percent share,[250] PDVSA had not yet committed to the partnership in RNEST and had failed to contribute to any of the costs incurred thus far.[251] Negotiations turned contentious as Petrobras objected to PDVSA's insistence on better-than-market prices for its crude oil supply for RNEST, and to PDVSA's revised intention to sell the refinery's products in Brazil instead of exporting them as had been initially proposed.[252] **Commercially Sensitive**

5. Phase IV: Project Execution

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107. Though during the Phase III assessment of RNEST, Petrobras still anticipated the refinery coming online by 2011, this timeline was extended as RNEST entered Phase IV and construction began in earnest. By Petrobras' 2009 20-F filing on May 19, 2010, Petrobras had revised expectations for RNEST, reporting an expected start in 2012.[255] A year later the 2010 20-F filing reported an expected start in 2013,[256] and a year after that RNEST was not expected to begin operations until 2014.[257]

108. In October of 2014, as construction of refining train 1 neared completion, Petrobras revised its total estimate for RNEST to US $18.9 billion.[258] Similar to the causes for revised estimates in the previous phases of RNEST, the explanations for this increase in estimated cost during Phase IV reflect common causes for cost increases and delays experienced by oil and gas megaprojects.

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[250] Petrobras Form 20-F for the Fiscal Year ended on December 31, 2007, p. F-49.
[251] Connors, Will, "Refinery Symbolizes Woes of Brazilian Oil Firm Petrobras," Wall Street Journal, December 7, 2014.
[252] "UPDATE: Brazil Petrobras, PDVSA Extend Refinery Talks 90 Days," Dow Jones News Service, May 26, 2009.

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Petrobras Form 20-F for the Fiscal Year ended on December 31, 2009, p. 41.
[256] Petrobras Form 20-F for the Fiscal Year ended on December 31, 2010, p. 40.
[257] Petrobras Form 20-F for the Fiscal Year ended on December 31, 2012, p. 36.
[258] **Commercially Sensitive**

Throughout RNEST's construction process, Petrobras experienced several project delivery challenges in addition to a continuation of the project planning shortfalls, geopolitical challenges and joint-venture challenges that plagued the project during earlier phases.

109. In its 2013 20-F, dated April 30, 2014, Petrobras reported that total investment in RNEST had reached US $14.8 billion and that construction was 84 percent complete.[259] RNEST's refining train 1 came online in December 2014, operating at a partial capacity of 74 MBPD.[260] Completion of refining train 2 (originally designated to process PDVSA's crude) was postponed for an unspecified period of time.[261] Petrobras attributed the adjusted delivery time of the project to various factors including "the necessity to hold new tenders [of contracts] because of excessive prices. Other factors were strikes, environmental conditions and the construction of infrastructure to access the project."[262] Petrobras' 2012-2016 business plan also attributed the increase in cost to "failures in physical and financial monitoring."[263]

110. The operating capacity for refining train 1 was limited by environmental regulations imposed by the State Environmental Agency. Per these regulations, the refining train may not operate above its current capacity of 75 MBPD until the SNOx unit (an emissions abatement unit) is completed.[264] The construction of the SNOx unit was halted when the project was put on hold, limiting the refining train's capacity significantly below its designed specifications.[265]

111. Project delivery challenges are also responsible for part of the increase in estimated cost.

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[259] Petrobras Form 20-F for the Fiscal Year ended on December 31, 2013, p. 38.
[260] Petrobras Form 20-F for the Fiscal Year ended on December 31, 2014, pp. 49, 112.
[261] Petrobras Form 20-F for the Fiscal Year ended on December 31, 2014, pp. 95, 112.
[262] Leahy, Joe, "Suape refinery wins political support despite escalating cost," Financial Times, March 26, 2014.
[263] "Petrobras Business Plan 2012-2016," June 25, 2012, p. 6.
[264] "Report on the Fair Value Measurement of Certain Assets," Deloitte, September 30, 2014 (DT000046), pp. 25, 27.
[265] "Report on the Fair Value Measurement of Certain Assets," Deloitte, September 30, 2014 (DT000046), pp. 25, 27.
[266] **Commercially Sensitive**

Other project delivery challenges manifested as delays for equipment delivery or completed work. **Commercially Sensitive**

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112. Commercial challenges also contributed to increases in total cost. Similar to Phase III, joint-venture conflicts continued to plague the project. PDVSA was repeatedly unable to secure the necessary financing.[269] Ultimately, I understand Petrobras abandoned the partnership with PDVSA. This required Petrobras to secure additional financing, and the expense of these additional loans had not been factored into Petrobras' previous estimates for the expense of the project.[270] Furthermore, Petrobras notes that adjustments had to be made to its calculation of tax benefits, and the interest expense of the loans Petrobras had secured from BNDES had not previously been included in the budgeting estimates. The net effect of these components (as some taxation adjustments resulted in savings for RNEST) was an additional expense of US $113 million.[271]

113. Geopolitical challenges related to macroeconomic conditions continued to affect the cost of RNEST during Phase IV. Petrobras estimated that an additional US $293 million in cost was due to changes in the exchange rate, and an additional US $2.110 billion in expenses were incurred due to stipulated contractual adjustment clauses that required adjustments for inflation.[272]

114. Finally, Petrobras attributed an additional US $2.573 billion in the increase in estimated cost to necessary contract amendments and negotiated claims.[273] As discussed further in Section VII.C., contract amendments in and of themselves are not surprising. Especially given the idiosyncratic nature of capital expenditure on oil and gas megaprojects in general, it would be unusual for an original contract to have sufficient provisions to cover all contingencies. This is perhaps even more true in the case of RNEST, where the project scope and design continued to

[269] "Loan Woes Could Force PDVSA Out Of Brazil Refinery JV -Reports," Dow Jones Energy Service, October 13, 2010; "Brazil Petrobras: PDVSA Failed To Get Refinery Loan Guarantees," Dow Jones Energy Service, February 7, 2012.
[270] *See* "Brazil may extend deadline for PDVSA participation in refinery," EFE News Service, September 12, 2012.
[271] RNEST 2014 Presentation, p. 8.[272] RNEST 2014 Presentation, p. 8.
[272] RNEST 2014 Presentation, p. 8.
[272] RNEST 2014 Presentation, p. 8.
[273] "Refinaria Abreu e Lima (RNEST)," Supply Investment Program Presentation," October 31, 2014 (PBRCG_00734761), p. 8.

change through much of the planning process. For example, Petrobras' internal investigation concluded that conducting contract bidding for the front-end engineering design at the same time that basic engineering work was still being done on the refinery "occasioned difficulties" including "the need in alterations in specifications during the bidding procedures and later during the performance of services."[274]

B. Rio de Janeiro Petrochemical Complex (Comperj)

1. Introduction

115. Petrobras began evaluating the possibility of building a new petrochemical complex in 2003, in light of Brazil's desire to achieve energy independence as discussed in Section III.B. Commercially Sensitive The complex was intended to process Brazil's own crude oil to meet the Brazilian petrochemical shortage.[276] The complex's location in Itaboraí, Rio de Janeiro placed the complex in the Southeast region, the largest consumer market in Brazil.[277] This complex became known as Comperj and was a part of the Brazilian government's development plan called PAC discussed in Section III.B.[278]

116. The preliminary plans for Phase I and Phase II were built around the idea of an integrated design consisting of a refinery and first and second generation petrochemical units as illustrated below in Exhibit 12. First generation petrochemical units produce basic petrochemicals (gas or liquid form), while second generation units produce intermediate petrochemicals (solid form).[279] Phase III saw an important change in the scope of Comperj's plans with the refining capacity doubling and the project's format shifting to the form of a program consisting of three steps, as illustrated in Exhibit 13 below.[280] Exhibit 14 illustrates how Phase IV resulted in even further

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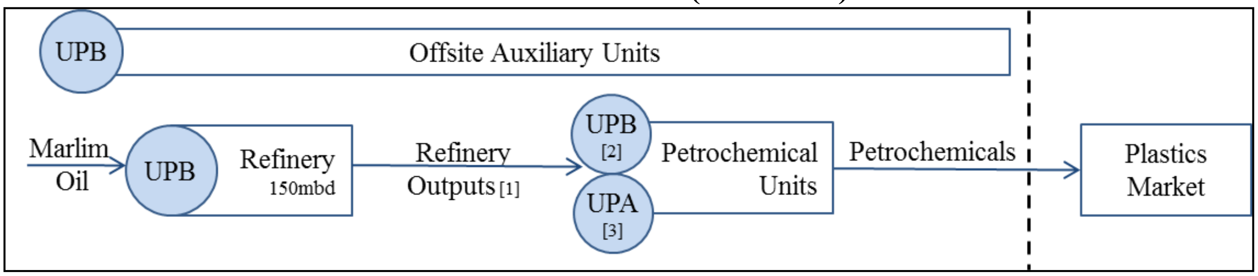
[274] RNEST CIA Report, pp. 8-9.
[275] Comperj EVTE I, p. 1.
[276] Comperj EVTE I, pp. 1-2, 8; Comperj CIA Report, DIP DABAST 70/2014, April 25, 2014 (PBRCG_00161490) ("COMPERJ CIA Report"), p. 9; "Historic - Supplying Portfolio Project," Comperj Program Presentation, February 4, 2016 (PBRCG_01788569) ("Comperj 2016 Presentation"), p. 2.
[277] The location changed from Itaguaí to Itaborai in Phase II, which is discussed in more detail below. *See* Comperj, p. 2.
[278] Comperj EVTE II 2006, p. 2; "PSD of Phase III of Project Comperj Refinery Train 1," February 24, 2010 (PBRCG00277692) ("Comperj Phase III PSD-English"), p. 7; Petrobras Form 6-K, "Main Petrobras Projects in the Growth Acceleration Plan (GAP)," January 23, 2007.
[279] "Petrochemical Industry," Braskem, http://www.braskem.com.br/cms/RI/Compartilhar/Pdf?titulo=petrochemical-industry&url=pXO82E6OuVTBfQr/94pCo2mOTgPZ+250Vd9AC5NG106OSLDMxneO2KW/Mr+HZmr1RMM+eG45cec= (last accessed on May 25,2016).
[280] Comperj EVTE III, p. 15.

scope changes, including increased refining capacity and the addition of a natural gas processing unit to supply the petrochemical units.

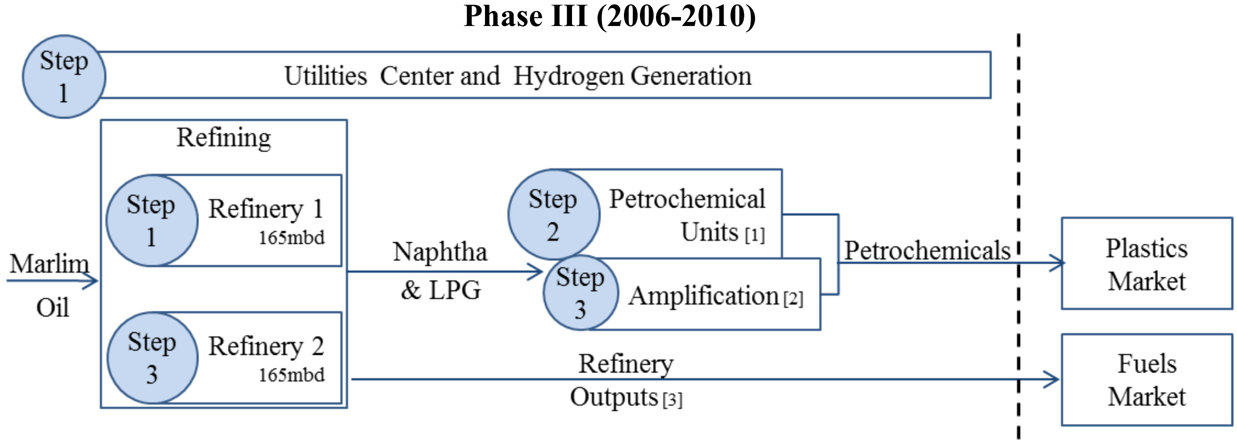
Exhibit 12
Phase I and Phase II (2003-2006)



Notes:
[1] Refinery Outputs include LPG, Naphtha, Ethane, Kerosene, and Gasoline.
[2] UPB stands for "Basic Petrochemical Units" and only included first generation petrochemical units.
[3] UPA stands for "Associated Petrochemical Units" and only included second generation petrochemical units.
[4] This exhibit is meant to illustrate how Comperj's units for the whole Complex would work together in theory.

Sources:
Comperj 2016 Presentation, p. 2.
TC 006.981/2014-3, October 15, 2014 ("TC 006.981/2014-3"), pp. 5-6.

Exhibit 13
Phase III (2006-2010)



Notes:
[1] Petrochemical Units include both first and second generation petrochemical units.
[2] Amplification includes a Petrochemical Fluid Catalytic Cracking Unit and an additional Polypropylene Train, which would allow for products to be further refined.
[3] Refinery Outputs include Diesel, Jet Fuel, LPG, Naphtha, Kerosene, and Coke.
[4] This exhibit is meant to illustrate how Comperj's units for the whole Complex would work together in theory, based on plans as of January 2010. However, not all units shown above were in Phase III at this point in time—Step 2 was in Phase II and Step 3 was in Phase I, which means they were not yet authorized for construction.

Sources:
Comperj 2016 Presentation, p. 2.
TC 006.981/2014-3, pp. 6-8.
Comperj EVTE III, pp. 3, 13, 23, 25-26, 28.
Comperj Phase III PSD-English, pp. 5, 10, 23.
"Comperj Program Presentation," February 25, 2010 (PBCRG_00277721) ("Comperj 2010 Presentation"), pp. 2-3, 9.

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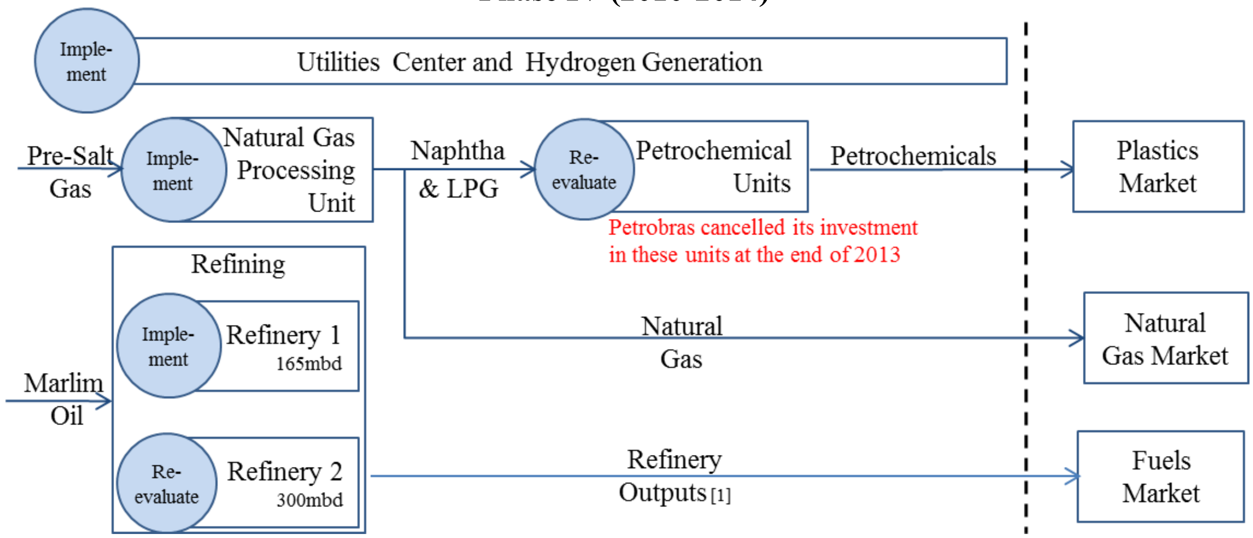
Exhibit 14
Phase IV (2010-2014)



Notes:
[1] Refinery Outputs include Diesel, Jet Fuel, LPG, and Naphtha. [
[2] This exhibit is meant to illustrate how Comperj's units for the whole Complex would work together in theory. However, not all units shown above were in Phase IV at this point in time—Refinery 2 and the Petrochemical Units were still under review and were not authorized for construction.

Sources:
Comperj 2016 Presentation, p. 5.
TC 006.981/2014-3, pp. 8-10, 69.
Comperj EVTE III, pp. 3, 15, 26.
Comperj Phase III PSD-English, pp. 5, 23.
"Final Report of the Internal Commission of Verification Instituted for 70/2014 DI P DABAST", April 25, 2014 (PBRCG_01336082) ("Comperj CIA Report Annex 5.1"), pp. 3, 8.

117. As the project moved beyond the assessment and conceptual design phases into engineering and execution, the estimated cost for the project was revised upwards significantly relative to initial estimates. As I discuss in detail below, these revisions were a function of changes in the project's scope, project management decisions, and the macroeconomic and regulatory context encompassing the construction. Similar to the RNEST project, no bids had been invited during Phase I or Phase II, so there exists no plausible rationale to claim that changes in scope or preliminary cost estimates that occurred as the project moved into Phase III could have alerted Petrobras' senior management to any possible corruption with respect to bidding or contracting. As the project moved into Phases III and IV, these same factors continued to drive cost estimate revisions. Similar to RNEST, against this backdrop of changing circumstances, which would likely have appeared to account for the increases in the project's estimated cost, it would be unreasonable to conclude that members of Petrobras' senior management could or should have

been able to identify a relatively small fraction of the increase in total costs that resulted from alleged overcharging by contractors.

2. Phase I: Assessment of Opportunity (2003-2004)

118. Phase I was an assessment of the investment opportunity in Itaguaí, which began in 2003.[281] It included a very high-level scope of the project and economic market analysis without the benefit of detailed engineering or a well-defined and confirmed scope for the project.

119. The initial project plan for Comperj consisted of two parts that would be integrated, the Basic Petrochemical Units ("UPB") and the Associated Petrochemical Units ("UPA"), together referred to as an Integrated Petrochemical Complex.[282] The UPB included a refinery with an operating capacity of 150 MBPD, first generation petrochemical units, and an offsite auxiliary utilities facility.[283] The UPA consisted of the second generation petrochemical units.[284] A Brazilian crude oil, known as "Marlim," would serve as the input for the refinery and the outputs from the refinery would, in turn, serve as inputs for the petrochemical units.[285] The complex was intended to produce petrochemicals (ethane, propane, benzene) and some oil-derived fuels (liquefied petroleum gas, diesel, and coke).[286] The Phase I study was done by Petrobras, Ultra Group and BNDES, and Petrobras planned to find partners and negotiate joint venture agreements to share the costs.[287]

3. Phase II: Conceptual Design (2004-2006)

120. After Phase I's assessment of Comperj was completed and approved in 2004, Petrobras began the Conceptual Design phase (Phase II) with the assistance of Technip, an integrative

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[281] Comperj EVTE I, p. 1; Comperj Phase II Presentation, August 2006 (PBRCG_00263565), PBRCG_00263567; "Unit of Production of Petrochemical Basic-UPB," July 2004 (PBRCG_01628570), PBRCG_01628570, 572, 574.
[282] Comperj 2016 Presentation, p. 2; Comperj EVTE I, pp. 1, 3.
[283] Comperj CIA Report, p. 9; Comperj 2016 Presentation, p. 2; Comperj EVTE I, p. 3.
[284] Comperj 2016 Presentation, p. 2.
[285] TC 006.981/2014-3, October 15, 2014 ("TC 006.981/2014-3"), p. 5; Comperj 2016 Presentation, p. 2.
[286] Comperj EVTE I, p. 2; "Unit of Production of Petrochemical Basic-UPB," July 2004, PBRCG_01628570, PBRCG_01628573, 01628575.
[287] Comperj EVTE I, pp. 1, 3; Comperj 2016 Presentation, p. 2.

company based in Italy hired to develop the design.[289] This phase involved some high-level engineering assessments and further development and refinement of the plans, including the decision to build Comperj in a different location than discussed in Phase I. The location for Comperj was shifted from Itaguaí to the municipality of Itaboraí, following the assessment of several options.[290] No bids were invited nor contracts executed during this time.[291]

121. **Commercially Sensitive**

122. **Commercially Sensitive**

123. The macroeconomic environment during this phase also shifted with the heating of the construction market, both domestically and internationally.[301] As Petrobras' Strategy and

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[301] *See* the discussion in the Edwards Report, Section 2, particularly section 2C, "Brazil Underwent a Construction Boom and Experienced Tight Labor Market Conditions."

Business Performance department pointed out, there was "strong pressure on the demand for critical resources" needed for Comperj including raw materials, equipment, and human capital.[302] Between 2004 and 2006, the price of steel had increased and inflation had increased.[303]

124. **Commercially Sensitive**

4. Phase III: Basic Engineering (2006-2010)

125. In 2006, Comperj progressed into the Basic Engineering Phase (Phase III), which concluded in January 2010, and involved more detailed engineering.[308] During this phase Petrobras executed contracts for a few services, began bidding for certain units, and began the earthworks in 2008.[309] This phase saw an important change in scope that represented a "break from the conceptual model" that had been developed in Phases I and II.[310]

126. Turning back to the five categories of common drivers of cost increases and delays for megaprojects identified above, Comperj encountered at least four out of the five of them during this time frame. Petrobras faced geopolitical challenges, development challenges, regulatory challenges, and changes in the commercial context of the Comperj project, as described below.

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[308] Comperj EVTE III, p. 1.
[309] Comperj Phase III PSD-English, p. 11; "PSD da Fase III do Projecto Comperj Refinaria Trem 1," PBRCG_00277692, p. 11.
[310] TC 006.981/2014-3, p. 6.

127. The geopolitical challenges faced during this phase included changes in the supplier and product markets. The global economic crisis had changed the consumption and supply of petrochemicals internationally and domestically.[311] Internationally, the demand for petrochemicals dropped as the global economy teetered on the brink of recession in 2008.[312] Domestically, Brazil's economy was booming, resulting in increased domestic demand for petrochemical products.[313] At the same time the international supplier markets for labor and construction materials continued to experience cost inflation, and domestic construction demands remained at or near Brazil's market capacity, leaving that market highly constrained and resulting in increased construction and infrastructure costs, and lengthened delivery times for various units.[314]

128. The result of these geopolitical challenges was that, during Phase III, Comperj's original scope became economically unattractive leading to substantial project development challenges.[315] In an effort to maximize profitability and make Comperj viable again, Petrobras

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129. Comperj underwent additional design changes related to the inputs that the refinery would use and the products that the refinery would produce. **Commercially Sensitive**

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[311] Comperj EVTE III, p. 3; TC 006.981/2014-3, p. 6.
[312] Comperj CIA Report Annex 5.1, p. 3.
[313] Jagger, Anna, "Petrochemical industry in Brazil finalizes consolidation," ICIS, March 31, 2008.
[314] Comperj EVTE III, pp. 2-3. *See also* Edwards Report, ¶2.26.
[315] Comperj EVTE III, p. 3.
[316] **Commercially Sensitive**
[317] **Commercially Sensitive**

Commercially Sensitive

Commercially Sensitive

130. Changes in design were also needed to meet changing expectations for future environmental regulations. Petrobras decided to maximize production of diesel with low sulfur content (50ppm or 10ppm) not only to fulfill the "increased demand for diesel with high quality standards," but also to adhere to "future quality requirements."[321]

131. Commercially Sensitive

132. Commercially Sensitive

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[321] Comperj EVTE III, pp. 3, 23.

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5. Phase IV: Execution Phase (2010-2014)

133. Following Phase III, Comperj began the Execution Phase (Phase IV) for Refinery 1 and infrastructure for the complex. During this period, bidding occurred, contracts were executed for the remaining services and units, and construction commenced. The project during this time continued to be affected by more changes in the commercial context, geopolitical challenges, project development challenges, and project delivery shortfalls which resulted in more substantial changes to the design of the project.

134. Project delivery deficiencies continued to affect the cost and timeline estimates for the project due to ineffective project management and poor contractor management. For example, several pieces of Ultra Heavy Over Size ("UHOS") equipment were among the advance purchases Petrobras made in 2010 prior to the completion of their basic designs and front-end engineering designs in Phase III[330]:

> Petrobras rated the UHOS equipment as critical for the implementation schedule for Refinery 1 because if they did not arrive at Comperj on the provided dates it would cause great impact on the units' construction contracts. Thus the Company committed to acquiring the special equipment directly and went ahead entering the contracts of the main processing units (UDAV, HCC, HDT and UCR), ensuring delivery of the UHOS on the assembling site within a pre-set time span.[331]

[330] Comperj CIA Report, pp. 16-17.
[331] TC 006.981/2014-3, p. 53.

135. **Commercially Sensitive**

136. The changes in the commercial context of the project consisted of partnership conflicts Petrobras encountered regarding the CDPU. In April 2010, Petrobras and SMU Energia e Serviços de Utilidades Ltda ("SMU"), a Brazilian company, had formed an independent company so that Petrobras could outsource the implementation of the CDPU at Comperj. SMU held an 80 percent interest in the company, while Petrobras had the remaining 20 percent.[335] However, in December 2011, "in light of the difficulty in formalizing the desired partnership for building and operating the CDPU, according to the planned parameters, Petrobras decided to carry out the works at its own expense," increasing the direct investment required of Petrobras beyond previous estimates.[336]

137. Petrobras encountered similar challenges in attempting other partnerships. In December 2011, Petrobras signed a Memorandum of Understanding ("MOU") with Braskem, but the document reflected the preliminary nature of negotiations for the partnership.[337] The MOU established that it would be up to Braskem to "develop studies of feasibility for the construction

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[335] Press Release, Petrobras, "New partnership for the development of Comperj," April 28, 2010, p. 20; Petrobras Form 6-K, "ITR-Quarterly Information as of 03/31/2010," May 24, 2010, p. 121; "TC 000.805/2015-7," p. 14; TC 006.981/2014-3, p. 44.
[336] TC 006.981/2014-3, p. 9; Petrobras Form 6-K, February 21, 2012, p. 70; "TC 000.805/2015-7," pp. 13-16.
[337] For example, the parties had not yet defined "how the partner company would share in the costs, [or] the reimbursement of utilities use[d]" or how they would be charged for their use of the raw materials. *See* TC 006.981/2014-3, p. 41.

of Comperj's petrochemical plants," but there was no deadline for the final investment decision.[338] This partnership remained undefined up through Comperj's postponement in 2014.

138. Petrobras also faced new geopolitical challenges during this time. Comperj's design went through a substantial revision in 2012 due to a technological development in the petrochemical industry. Because of new drilling techniques, the production of natural gas from shale rock in the United States had increased substantially, bringing down its price.[339] In addition, production of natural gas in Brazil had increased substantially, and it was expected to continue increasing due to the abundance of natural gas in the recently discovered pre-salt reserves.[340] Commercially Sensitive

139. By the end of 2013, Petrobras decided to cancel its investment in the Petrochemical Units altogether, which resulted in more of the shared infrastructure costs being shifted to Refinery 1.[346] In 2014, Comperj encountered further challenges including workforce disruptions, further changes in the scope, and increasing costs. Several worker strikes caused further delays in the

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338 TC 006.981/2014-3, pp. 41-42.

339 Mufson, Steven, "The new boom: Shale Gas fueling an American industrial revival," The Washington Post, November 14, 2012.

340 *See* "World Energy Outlook 2011," International Energy Agency, p.167; "World Energy Outlook 2012," International Energy Agency, p.141; "World Energy Outlook 2013," International Energy Agency, p. 365.

Commercially Sensitive

Comperj CIA Report Annex 5.1, pp. 8, 9.

timeline including a 40-day strike that shut down all work at Comperj, which ended in March 2014.[347]

140. At the end of 2014 Petrobras postponed work on Refinery 1 and the shared infrastructure, with work about 85 percent complete.[348] After the project was postponed, Petrobras' 2015-2019 Business Plan estimated that the cost for Refinery 1 and shared infrastructure would be US $16.5 billion.[349] The timetable was also delayed, with Refinery 1 expected to start operating in January 2021.[350]

C. Response to Dr. Henning's Claims Related to Contract Amendments and Alleged Overpayments

141. Dr. Henning claims that Petrobras management was put on notice as early as 2009 by inspection reports issued by *The Tribunal de Contas da União* ("TCU," the Brazilian federal accountability office) that there were significant deficiencies in Petrobras' internal controls, citing the high number of contract amendments and evidence of overpayments in relation to the market. In Dr. Henning's view, these findings in the TCU reports constituted "red flags" that should have alerted Petrobras management, directors, and audit committee and caused them to take actions to correct deficiencies in Petrobras' bidding and procurement systems.[351]

142. In my opinion, neither the contract amendments nor the alleged overpayments highlighted by Dr. Henning should have been construed as red flags with respect to corruption or poor internal controls by Petrobras management. As I explained in Section V above, for large complex oil refinery projects like RNEST and Comperj, high cost overruns and contract amendments, often triggered by delays and changes in scope, are the norm rather than the exception. In the case of the RNEST refinery, the lack of necessary regional infrastructure to

[347] "Brazilian workers end Comperj refinery strike," BN Americas, March 17, 2014, http://www.bnamericas.com/en/news/oilandgas/brazilian-workers-end-comperj-refinery-strike; "Challenges across Brazil's oil sector and prospects for future production," The Oxford Institute for Energy Studies, October 2014, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2014/10/WPM-55.pdf, p. 9; "An oil scandal in Brazil complicates the race for incumbent president on eve of election," The Washington Post, October 2, 2014, https://www.washingtonpost.com/world/an-oil-scandal-in-brazil-complicates-the-race-for-incumbent-president-on-eve-of-election/2014/10/01/f2df5d90-c279-11e3-b574-f8748871856a_story.html.

[348] Petrobras Form 20-F for the Fiscal Year Ended on December 31, 2014, p. 112; Petrobras Form 6-K, "Petrobras Annual Shareholders Meeting on April 29, 2015," July 8, 2015, p. 27.

[349] In the same Business Plan, US $24.03 billion was the estimated cost for the entire project, much of which was still under evaluation and had not been authorized for construction. *See* Comperj 2016 Presentation, pp. 4-5, 9.

[350] Comperj 2016 Presentation, p. 8.

[351] Henning Report, pp. 1-34 to 1-35, 1-44.

support a refinery on this scale, changes in the project's scope and management, and joint venture conflicts, among other things, contributed to contract amendments, delays, and increased costs.[352] The Comperj refinery similarly faced increased costs, delays, and contract amendments caused by changes in the project's scope, project management decisions, macroeconomic conditions, change in location, and the regulatory environment. Thus, for bespoke projects such as RNEST and Comperj, contract amendments would have reflected the complexity of the project, rather than a sign of irregularity. In my opinion, Dr. Henning's claim that amendments to these projects were red flags suggesting corruption or problems in internal controls is predicated on a flawed understanding of refining megaprojects.

143. Moreover, even accepting Dr. Henning's estimates of overpayments on RNEST and Comperj for illustrative purposes only, the alleged overpayment amounts would not have been large enough to have been noticeable as red flags to Petrobras senior management. Compared to the Phase III funds authorization budgets for the projects, the overpayments alleged by Dr. Henning represent increases of 17 and 7 percent for RNEST and Comperj, respectively,[353] well below the average cost increases typically experienced by megaprojects relative to budget at funds-authorization.[354]

VIII. Analysis of Petrobras' Acquisition of the Pasadena Refinery

144. In September of 2006, Petrobras and Astra closed on a $360 million transaction which gave Petrobras a 50 percent stake in a 100 MBPD refinery in Pasadena, TX and a 50 percent stake in a trading company.[355] Plaintiffs claim that Petrobras overpaid for the refinery and that this should have been clear given that Astra paid $42.5 million when they purchased the refinery from Crown Central Petroleum Corporation ("Crown") in January of 2005.[356] It is my opinion that the

[352] *See*, for example, RNEST CIA Report Addendum, pp. 1-85, for discussion of causes of contract amendments.
[353] For RNEST, this is the percentage increase over the US$13.362 billion phase III budget represented by Dr. Henning's alleged overpayments of US$2.33 billion (converted from R$6.2 billion using the exchange rate as of December 31, 2014). For Comperj, this is the percentage increase over the US$11.2 billion phase III budget for Refinery train 1 with shared infrastructure (the only part of the project given funds authorization at that stage) represented by Dr. Henning's alleged overpayment of US$0.75 billion (converted from R$2.0 billion using the exchange rate as of December 31, 2014). *See* Henning Report, pp. 4-18 and 4-23; RNEST EVTE III 2009, p. 3; Comperj 2010 Presentation, p. 28. According to the IRS Treasury reporting Rates of Exchange, as of December 31, 2014, the exchange rate was 2.657 Brazilian Real per US Dollar.
[354] *See* Section V.A.
[355] Petrobras Form 6-K, "Petrobras closes deal to acquire 50% of Pasadena Refinery," September 1, 2006, p. 2.
[356] Fourth Amended Complaint, ¶97.

purchase price agreed to between Petrobras and Astra for the sale in September of 2006 was consistent with transaction prices involving other refineries and therefore should not have raised any red flags regarding corruption or other governance issues. I describe below Petrobras' motivation for seeking to purchase a refinery or enter into a joint venture in one outside of Brazil, Astra's acquisition of and subsequent investments in the Crown Pasadena refinery, and how the price agreed to by Petrobras compared to other refinery transactions in 2005 and 2006.

A. Petrobras Refine Abroad Project

145. In late 1999, Petrobras decided to explore international refining opportunities.[357] Petrobras established the "Refine Abroad" project in 2000 and retained the consulting firm Aegis Muse ("Muse") to perform "market analysis of the US downstream market, the identification of potential partners and target assets, selection of the best business opportunities, value analysis and structuring of partnerships (joint ventures)."[358] In April 2002, Muse identified the top 25 international targets Petrobras should consider, including the Pasadena refinery.[359]

146. In a February 2008 study for Petrobras, Muse benchmarked refinery transactions from May 2000 through May 2007 based on the sale price per barrel of refining capacity. In Exhibit 15 below I have plotted the results of Muse's findings for transactions from 2000 through 2006, which corresponds to the time period from when Petrobras established the Refine Abroad project through their purchase of the Pasadena refinery. As this exhibit shows, when Petrobras first began exploring international refinery opportunities from 2000 through 2002, prices per barrel of refinery capacity for the eight transactions during that period ranged from $1,269 to $5,729. Muse also found that in 2003 and 2004, the price per barrel of refining capacity fell to between $172 and $3,185 for the eight transactions during those years.[360]

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[357] "Final Report of the Internal Investigation Committee established by the DIP Presidencia 38/2014," October 2014 (PBRCG_00161534), ("Pasadena CIA Report"), p. 3.
[358] Pasadena CIA Report, p. 3.
[359] Pasadena CIA Report, pp. 3-4.
[360] The second-lowest price per barrel of refining capacity was $600. *See* "Pasadena Refinery Valuation Update for Petrobras Justification for Current Value," Muse Stancil, February 26, 2008, p. 9 ("Pasadena 2008 Valuation Presentation").

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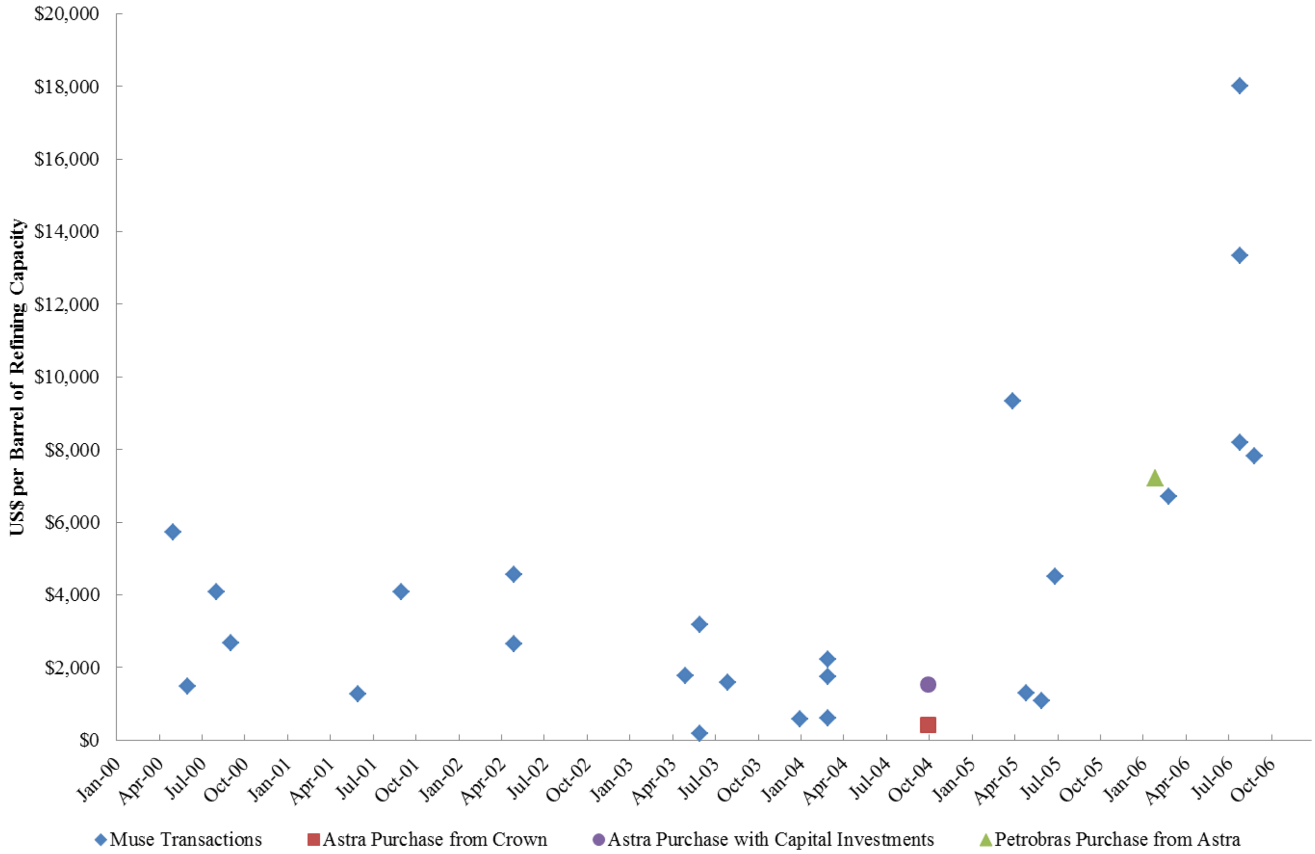
Exhibit 15
Refinery Transaction Price per Barrel of Refining Capacity
2000 – 2006



Notes:
[1] Muse transaction dates represent the date when transactions were announced, rather than closed. Muse transaction prices do not appear to include inventory values or any other adjustments made at closing.
[2] Muse presents data on 8 transactions announced between March 2000 and May 2002. A September 2001 transaction between Tesoro and BP involved 2 different refineries.
[3] Muse presents data on 8 transactions announced between May 2003 and March 2004.
[4] Muse presents data on 10 transactions announced between April 2005 and September 2006. A transaction announced in April 2005 between Valero and Premcor involved 4 different refineries.
[5] The Astra purchase from Crown is shown in October 2004, when the companies agreed to the purchase.
[6] The Petrobras purchase from Astra is shown in February 2006, when the Petrobras Board of Directors approved the transaction.
[7] "Astra Purchase with Capital Investments" includes the $42.5 million purchase price plus $112 million in capital investments in the refinery made by Astra.

Sources:
Pasadena CIA Report.
Muse Pasadena 2008 Valuation Presentation.

B. Astra Acquisition of and Investments in PRSI

147. Based on the terms of a processing agreement between Astra and Crown regarding the Pasadena refinery,[361] Astra was granted the opportunity "in its sole and absolute discretion….to purchase or to not purchase the Refinery from Crown at the conclusion of [the] Agreement."[362] On October 22, 2004, Astra agreed to purchase PRSI from Crown for $42.5 million, which excluded the costs associated with the refinery's inventory, a price of $425 per barrel of PRSI's processing capacity, at the low end of the range of transactions that had closed in the prior two years. The deal was closed on January 25, 2005.[363]

148. From January 2005 through August 2006, Astra invested approximately $112 million in the refinery to improve its performance and operations:

- US$ 35 million were for the construction of the S-Zorb unit (in order to achieve the sulphur content for gasoline required by American law),
- US$ 51 million in capital invested in maintenance 'stoppages' for production units,
- US$ 12 million in improvements in the safety and reliability of the facilities, and
- US$ 14 million in investments in operating systems.[364]

149. The addition of the S-Zorb unit was a particularly important upgrade as it allowed the refinery to meet the new gasoline regulations and sell gasoline into the American market.[365] Astra's purchase and subsequent capital expenditures to improve the quality of the refinery amount to approximately $154.5 million. This equates to $1,545 per barrel of PRSI's processing capacity, which was near the middle of the range of transactions between 2003 and 2004 as shown in Exhibit 15.

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[361] Beginning June 15, 2004, Astra and Crown entered into an agreement wherein Crown agreed to process at least 85 MBPD of crude oil supplied by Astra for a $3.25 to $6.00 per barrel processing fee, depending on the type of crude. *See* "100% Processing Agreement between Astra Oil Company, Inc. and Crown Central Petroleum Corporation," June 2004 ("Pasadena Processing Agreement"), pp. 2, 5, 8-9. The term of the Agreement was 90 days, which could be extended by mutual consent. The agreement was renewed through January 25, 2005. *See* Pasadena CIA Report, p. 6.

[362] Pasadena Processing Agreement, p. 14.

[363] Pasadena CIA Report, p. 6.

[364] Pasadena CIA Report, p. 7.

[365] *See,* for example, "STEO Supplement: Summer 2006 Motor Gasoline Prices," EIA, 2006, p. 5, https://www.eia.gov/forecasts/steo/special/pdf/gasoline2006.pdf; and "Pasadena refinery sold to California company," Houston Chronicle, January 26, 2005, http://www.chron.com/business/energy/article/Pasadena-refinery-sold-to-California-company-1943482.php.

C. Petrobras Acquisition of PRSI

150. Petrobras and Astra began negotiations for a partial sale of PRSI on August 19, 2005 when Petrobras submitted an offer to Astra in the amount of $365 million for a 70 percent share in PRSI (equivalent to $520 million for 100 percent).[366] Astra submitted a counteroffer of $475 million for a 70 percent share (equivalent to $680 million for 100 percent).[367] Negotiations continued between the parties for a 50 percent share of the business, and the Petrobras Board of Directors approved a purchase price of $359 million on February 3, 2006.[368] This purchase price is equivalent to $7,180 per barrel of processing capacity for 100 percent of the refinery.[369]

151. In 2005 and 2006, refinery transaction prices had increased significantly, consistent with the broader changes in the global oil market I describe in Section IV. As shown in Exhibit 15, Muse reported transactions increasing from $1,071 per barrel capacity for a transaction in June 2005 to a high of over $18,000 per barrel capacity for a transaction in August 2006.[370] Muse indicated that Valero's purchase of Premcor's four refineries, which was announced in April 2005 and completed in September of 2005 while Petrobras and Astra were in negotiations, transacted at $9,329 per barrel of processing capacity.[371] The $7,200 per barrel capacity paid by Petrobras[372] is therefore completely consistent with the prices being paid for refineries in this period of increasing prices.

152. As described in Section III.A., a more complex refinery which can process heavy, sour crude oil will be more expensive to build (or purchase) than a less complex refinery that may only be able to process light, sweet crude oil. Muse therefore normalizes the transaction prices

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[366] Pasadena CIA Report, p. 15.
[367] Pasadena CIA Report, p. 16.
[368] Pasadena CIA Report, p. 36.
[369] As part of the purchase agreement, Petrobras agreed to reimburse Astra for a portion of the S-Zorb unit construction costs. *See* "Stock Purchase and Sale Agreement and Limited Partnership Formation Agreement between Petrobras America, Inc. as Buyer and Astra Oil Trading NV and Astra Oil Company, Inc. as Seller," February 2006, pp. 22-26; "Closing Agreement By and Between Petrobras America Inc., Astra Oil Trading N.V. and Astra Oil Company, LLC," August 31, 2006, Exhibit A. Adding Petrobras' $37 million share of the costs for this unit to the 100 percent basis purchase price increases the price per barrel paid by Petrobras to $7,570.
[370] Pasadena 2008 Valuation Presentation, p. 9.
[371] Pasadena 2008 Valuation Presentation, p. 9.
[372] For these analyses, I used the $360 million price reported by Petrobras for its 50 percent stake. Muse's listed purchase price for PRSI is $370 million ($740 million for a 100% stake), which is higher than the actual price agreed to by the parties. The source of this discrepancy is unclear. Muse also lists November 2005 as the transaction date, but this appears to be based on the public announcement of a MOU between Petrobras and Astra. A price had not yet been agreed upon. *See* "Memorandum of Understanding for refining in the USA," Petrobras, November 16, 2005, http://www.investidorpetrobras.com.br/en/press-releases/memorandum-understanding-refining-usa.

to account for the differences in the complexity of the refineries using two metrics: price per complexity barrel and the price as a percentage of the estimated replacement cost.[373] The price Petrobras paid for their stake in PRSI is consistent with other transactions in the same time period when one looks at these metrics as well. Exhibit 16 below plots the price per complexity barrel reported by Muse. In 2005 and 2006, the price per complexity barrel ranged from $171 to $1,822 (Valero paid $885 for Premcor's refineries), compared to $857 per complexity barrel paid by Petrobras. Exhibit 17 plots the price as a percentage of the refinery's estimated replacement cost reported by Muse. The transaction price as a percent of replacement cost varied widely in 2005 and 2006. The average transaction in this period was 53 percent of replacement cost (Valero paid 71 percent of the estimated replacement costs for Premcor's refineries), compared to 71 percent of replacement cost paid by Petrobras.[374] The 2005 through 2006 average is more than double the 20 percent average for the 2000 through 2004 transactions.

[373] A refinery's complexity is based on an index used "to quantify the relative cost of components that make up a refinery" and "provides a relative measure of the construction costs of a particular refinery based on its crude and upgrading capacity." Complexity barrels are calculated by multiplying the refinery crude oil processing capacity by the complexity index. The minimum value the index can take is 1, and the index increases depending on the amount and type of equipment the refinery has. *See* Johnston, Daniel, "Refining Report Complexity index indicates refinery capability, value," Oil & Gas Journal, March 18, 1996.
[374] Pasadena 2008 Valuation Presentation, p. 9.

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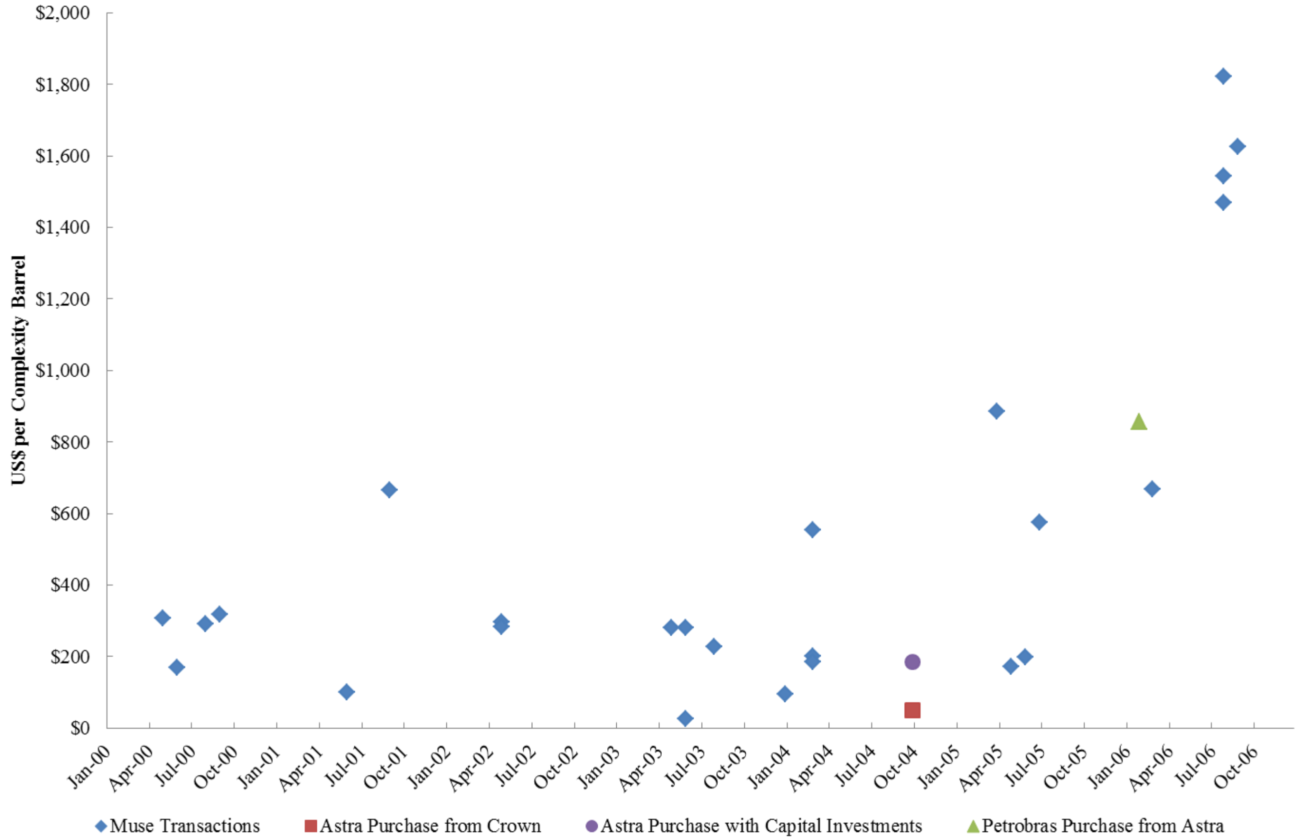
Exhibit 16
Refinery Transaction Price per Complexity Barrel of Refining Capacity
2000 – 2006



Notes:
[1] Muse transaction dates represent the date when transactions were announced, rather than closed. Muse transaction prices do not appear to include inventory values or any other adjustments made at closing.
[2] Muse presents data on 8 transactions announced between March 2000 and May 2002. A September 2001 transaction between Tesoro and BP involved 2 different refineries.
[3] Muse presents data on 8 transactions announced between May 2003 and March 2004.
[4] Muse presents data on 10 transactions announced between April 2005 and September 2006. A transaction announced in April 2005 between Valero and Premcor involved 4 different refineries.
[5] The Astra purchase from Crown is shown in October 2004, when the companies agreed to the purchase.
[6] The Petrobras purchase from Astra is shown in February 2006, when the Petrobras board approved the transaction.
[7] "Astra Purchase with Capital Investments" includes the $42.5 million purchase price plus $112 million in capital investments in the refinery made by Astra.

Sources:
Pasadena CIA Report.
Muse Pasadena 2008 Valuation Presentation.

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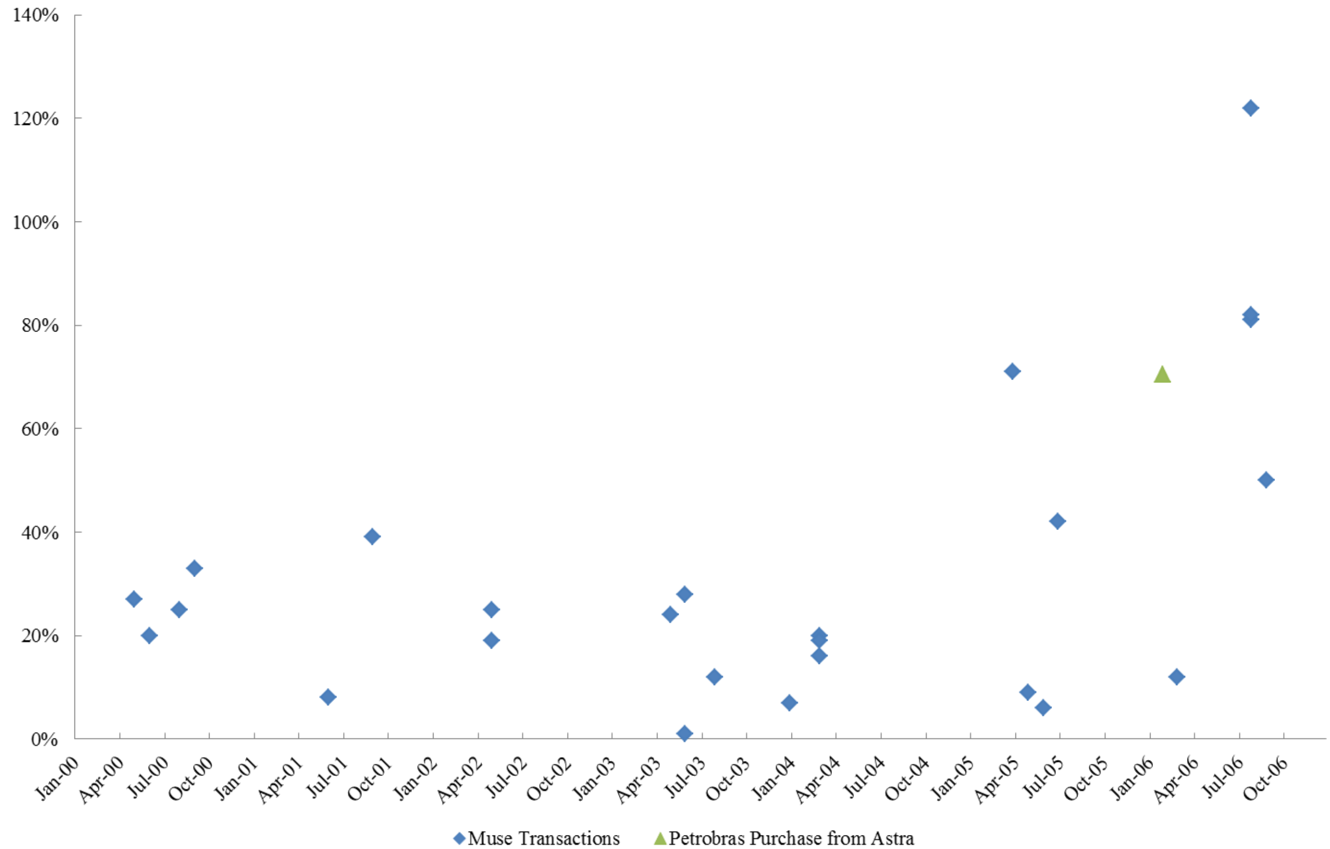
Exhibit 17
Refinery Transaction Price as a Percentage of Replacement Value
2000 – 2006



Notes:
[1] Muse transaction dates represent the date when transactions were announced, rather than closed. Muse transaction prices do not appear to include inventory values or any other adjustments made at closing.
[2] Muse presents data on 8 transactions announced between March 2000 and May 2002. A September 2001 transaction between Tesoro and BP involved 2 different refineries.
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[5] The Petrobras purchase from Astra is shown in February 2006, when the Petrobras board approved the transaction.
[6] Muse did not present data for the Astra purchase from Crown which closed in January 2005. Therefore, the estimated replacement cost at that time is unknown.

Sources:
Pasadena CIA Report.
Muse Pasadena 2008 Valuation Presentation.

153. This analysis is consistent with Citigroup's February 2006 fairness opinion. Citigroup found that "Comparable Companies Replacement Value," adjusted for a 50 percent ownership stake, was between $436 million and $567 million, and that a valuation based on "Precedent Transactions Complexity Barrels" would be between $252 and $378 million for a 50 percent

ownership stake.[375] Even using the more conservative valuation based on "Precedent Transactions Complexity Barrels," the $360 million purchase price agreed to between the parties still falls in the range estimated by Citigroup.

154. During the period when Petrobras acquired its 50 percent stake in PRSI, refinery prices were increasing dramatically, as demonstrated by Exhibits 15, 16, and 17. Citigroup pointed this out in its fairness opinion, noting "Global refinery utilization rates at record levels as industry tries to keep pace with increasing demand."[376] Citigroup also pointed out that:

> Recently, replacement cost and transaction multiples have spiked due to:
>
> - Fundamental shift in market dynamics resulting in much improved refinery economics
> - Scarcity of assets available for sale
> - Integration attempts by Canadian heavy crude producers.[377]

155. These market factors persisted through 2007, after Petrobras purchased 50 percent of PRSI. Muse noted in February 2008 that "refinery sales price, expressed as a percent of replacement cost, has shown a significant upturn over the past several years. With the market reacting to the forecast for tight product supply and the perception that associated high refinery margins will continue, transactions have been closing above historical norms."[378]

156. In summary, there is no economic rationale to claim that the price paid by Petrobras for a 50 percent stake in Astra's Pasadena refinery in September 2006 should have alerted senior management to bribes being paid or other corporate governance issues. The difference in the price paid by Astra in January 2004 and the price Petrobras paid in September 2006 can be explained by changing market conditions over the course of this time period, which led to escalating transaction values, as shown in Exhibits 15, 16, and 17, and the subsequent capital investments that Astra made after it purchased the refinery from Crown.

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[375] "Project Rose Bowl – Presentation to the PBR Board of Directors," Citigroup, February 2006 ("Citigroup Presentation"), p. 7.
[376] Citigroup Presentation, p. 24.
[377] Citigroup Presentation, p. 29.
[378] Pasadena 2008 Valuation Presentation, p. 8.

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Appendix A

CURRICULUM VITAE

Name:	Philip K. Verleger, Jr.
Date of Birth	July 18, 1944
Education:	A.B. in Economics (cum laude), Cornell University, June, 1966.
	Ph. D. in Economics, Massachusetts Institute of Technology, 1971.
Career:	President, PKVerleger LLC 1997 - present.
	David Mitchel/Encan Professor of Global Strategy, Haskayne School of Business, University of Calgary 2008 - 2011.
	BP Senior Fellow, Council on Foreign Relations 2002 – 2003.
	Charles River Associates, Vice President, 1994 – 1997.
	Visiting Fellow, Peterson Institute of International Economics 1985 - 1994. 2005- 2012.
	Drexel, Burnham, Lambert, Inc., Vice President, 1982 - 1984.
	Booz, Allen and Hamilton, Inc., 1981 - 1982.
	Yale University School of Organization and Management, Lecturer, 1980 – 1982, Senior Research Scholar, 1979 - 1981.
	U.S. Department of the Treasury, Special Assistant to the Assistant Secretary for Economic Policy, 1977 -1979.
	Executive Office of the President, Council of Economic Advisers, Senior Staff Economist, 1976 - 1977.
	Data Resources, Inc., Manager, DRI Energy Service, 1971 - 1976.
	University of California, Santa Barbara, Acting Assistant Professor of Economics, 1970 - 1971.
Memberships:	National Petroleum Council American Economic Association American Finance Association Council on Foreign Relations

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1997 by PKVerleger LLC. 373 issues through July 2013.

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Activities as an Expert Witness or Consultant on Litigation

I.A.M. vs. OPEC: Expert witness for Judge Andrew H. Hauk, U.S. District Court Judge, Los Angeles, California. Appeared in court on August 18, 1979 (date approximate).

Shepherd Oil vs. Arco: Expert witness for ARCO in case relating price charge for oil sold under the mandatory buy sell program. Employed by Ball, Hunt, Brown and Baerowitz. Case settled before reaching trial. Fall 1981 to Spring 1982.

Hunt Oil vs. DOE: Expert witness in the "V factor matter." Prepared memorandum for attorneys Shank, Irwin, Dallas (Karen Bidel was partner in charge).

Shell Oil vs. Newport News and Dry-dock Co. Expert for Shell's attorney Cadwallader, Wickersham and Taft (H. Clayton Cook). Prepared information of oil price forecast. Case settled on courthouse steps.

Champlin Petroleum vs. Union Oil Company. Expert witness for Champlin Petroleum in arbitration with Union Oil over a contract to supply products from Champlin's refinery to Union Oil's Los Angeles Refinery. Appeared for Champlin's attorney Paul, Weiss, Rifkind, Wharton and Garrison (Robert Montgomery). Appeared in February 1984.

APEX vs. DiMauro. Expert witness for four companies in a Sherman Act/Commodity Futures Act dispute relating to certain events that occurred on the New York Mercantile Exchange in February 1982. I was retained by Michael Lesch of Shea and Gould. In addition, I worked for Nutter, McLennen & Fish, attorneys for Northeast Petroleum, Katten, Muchin & Zavis, attorneys for Stinnes Interoil; and Brenner, Saltzman, Wallman & Goldman, attorneys for G.E. Warren. Deposed in 1986.

Alaska Department of Revenue vs. Exxon. Expert witness for Exxon concerning the appropriate price to use for Alaskan crude oil in Exxon's 1978 income tax. Worked with Tom Foster, Exxon's in house tax counsel.

State of Alaska vs. Exxon. Expert consultant for Exxon concerning the appropriate price to use to value royalty oil taken in kind by Exxon. Worked with John Held of Baker and Bots and Exxon lawyers.

Exxon vs IRS. Expert consultant for Exxon concerning conditions in the world oil market in 1979 and 1980 and their relationship to the price that prevailed for term as opposed to spot supplies of oil.

Massachusetts Refusetech Inc. vs. North East Solid Waste Committee: Expert consultant for North East Solid Waste Committee on the predictability of the oil price decline.

Castle Oil vs. Castle Energy: Expert witness for Castle Oil in a litigation over name confusion. Testified in U.S. Federal court on April 22, 1992. Substance of testimony was on the structure of the world oil industry.

Aerochem vs. Johnston: Expert consultant to major stockholders for Aerochem concerning the trading practices of the president of Aerochem.

Tecumseh Pipeline vs. Laketon Refining: Expert consultant to major owners of Tecumseh Pipeline (Arco, Ashland

and Unocal) in litigation related to the antitrust implications of shutdown of the pipeline.

Metallgesellschaft vs. Benson: Expert consultant and witness to Metallgesellschaft in arbitration with W.A. Benson concerning the latter's management of Metallgesellschaft's refining and marketing company. Testified for three days for MG in the fall of 1995.

Thorton vs. Metallgesellschaft: Expert witnesses for Metallgesellschaft concerning Metallgesellschaft's risk management practices. Testified in the fall of 1994 and spring of 1995.

New York Mercantile Exchange v. New Jersey Department of Environmental Protection, Civil Action No. CV-959-2314(AEfT), U.S. District Court for New Jersey, April 1995. Prepared affidavit for New York Mercantile Exchange.

The Allen Trusts v. Union Pacific Fuels: Appeared as an expert witness in arbitration relating to the price of natural gas. 1996.

The Department of Justice Investigation of the 1996 Increase in Gasoline Prices: Served as an expert consultant to the DOJ investigation on this matter.

Frederick Ashmore, David Boya, William Simone, and Richard Simone v. Northeast Petroleum, a division of Cargil Inc. Northeast Petroleum of Maine, Northeast Petroleum of Cape Cod, d/b/a Northeast Petroleum and Cargil Inc.; Docket 93-199-P-C, U.S. District Court, District of Maine. Robinson-Patman Act litigation filed in federal court in Maine between former employees of Northeast Petroleum and Northeast concerning pricing practices of petroleum products. Matter settled before trial.

Theresa Aguilar et. al. v. Atlantic Richfield et. al.: Expert consultant to Diamond Shamrock-Ultramar. Deposition November. 1997.

In Re: Florida Power & Light Company, Manatee Orimulsion Project. Appeared as rebuttal witness for Florida Power and Light. 1998.

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Gallagher Kornish, Lieb, Weiner & Hellman LLP. Filed testimony as expert for Coastal Corp.

Prewitt Enterprises, Inc. vs. Organization of the Petroleum Exporting Countries, Civil Action CV-00-W-0865-S, Northern District of Alabama, Southern Division, Prepared Affidavit. January 2001.

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